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Advanced Utility Simulation Model Description of Modifications to the State Level Model (Version 3.0)

Science Applications International Corp.
McLean, VA

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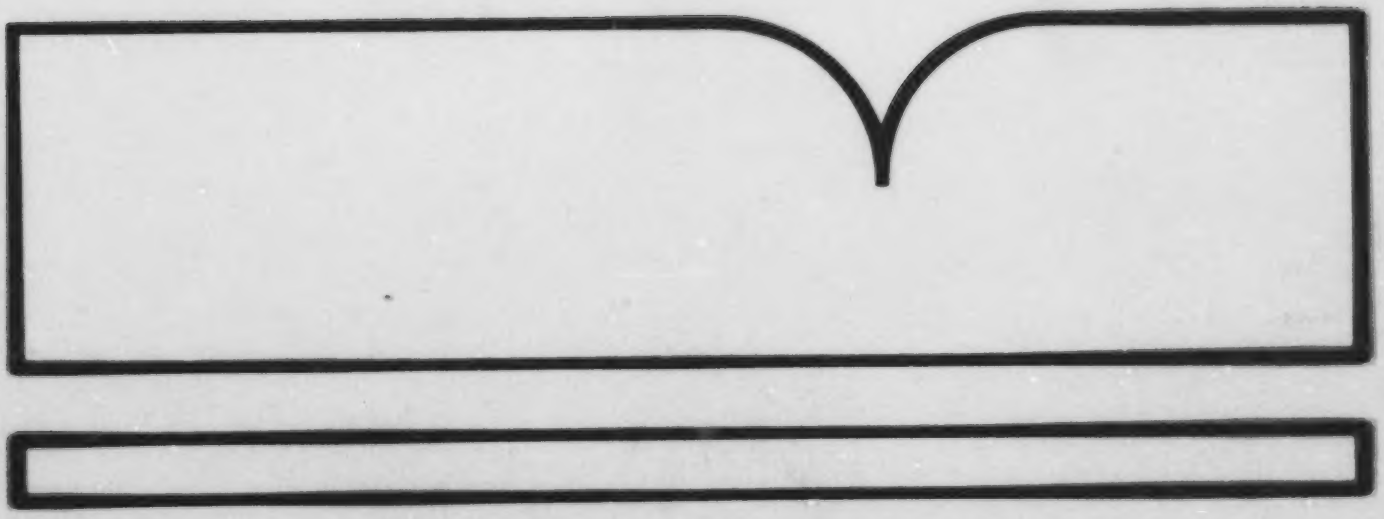

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ADVANCED UTILITY SIMULATION MODEL DESCRIPTION OF MODIFICATIONS TO THE STATE LEVEL MODEL (VERSION 3.0)

by

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16. ABSTRACT The report documents modifications to the state level model portion of the Advanced Utility Simulation Model (AUSM), one of four stationary source emission and control cost forecasting models developed for the National Acid Precipitation Assessment Program (NAPAP). The AUSM model, originally developed in two principal parts (the national loop and the state level model), projects air pollution emissions (SO2, NOx, and particulate matter), costs of generation and pollution control, and electric rates by consumer category by state and year. The state level model modifications followed testing and review that identified four types of required revisions: (1) correction of coding errors which caused syntactical or logical problems; (2) addition of new knowledge about electric utility operations, generating and emissions control equipment, ways in which users wish to run the model, and user information needs; (3) modification of components to permit calibration of AUSM to more accurately simulate the historical years, 1980-1985; and (4) incorporation of changes in external factors such as new tax requirements and financing trends. Only Revisions 2, 3, and 4 are included in this volume. Revision 1 modifications are documented in the source code by comment.

17. KEY WORDS AND DOCUMENT ANALYSIS			
a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Sulfur Dioxide	Pollution Control	13B 07B
Utilities	Nitrogen Oxides	Stationary Sources	
Emission	Fuels		14G 21D
Cost Analysis	Electrical Power Demand		14A
Simulation			20C
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This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

ABSTRACT

The Advanced Utility Simulation Model (AUSM) is one of four stationary source emission and control cost forecasting models developed by the Air and Energy Engineering Research Laboratory for the National Acid Precipitation Assessment Program. The AUSM Model projects air pollution emissions (sulfur dioxide, nitrogen oxides and particulate matter), costs of generation and pollution control, and electric rates by consumer category by state and year.

The AUSM Model was originally developed by the Universities Research Group on Energy (URGE) in two principal parts: the national loop and the state level model. This report documents the work performed by the Science Applications International Corporation (SAIC) research team in revising the state level model. The AUSM state level model was extensively modified by the SAIC team after testing and review identified needed changes. Four types of revisions were made:

- Coding errors which caused syntactical or logical problems were corrected. These modifications are transparent to the user.
- New knowledge about electric utility operations, generating and emissions control equipment, ways in which users wish to run the model, and user information needs were added.
- Calibration of AUSM to more accurately simulate historical years, 1980 - 1985, required modification of some components.
- Changes in external factors, such as new tax requirements and financing trends, were incorporated.

Only the last three types of revisions are included in this volume. Modifications which correct coding errors are documented in the source code via comment.

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ABBREVIATIONS

ITEM	DESCRIPTION
AFUDC	Allowance for funds used during construction
AUSM	Advanced Utilities Simulation Model
Btu	British thermal units (1 Btu = 1.055 kJ)
Ca/S	Calcium to sulfur mole ratio
CF	Capacity factor
FIPS	Federal Information Processing Standard
HHV	Higher heating value
ITC	Investment tax credit
kW	Kilowatts (1 kW = 1 kJ/s)
kWh	Kilowatt hours (1 kWh = 3.6 MJ)
LDC	Load Duration Curve
LIMB	Lime Injection Multi-stage Burner
MMBtu	Million British thermal units (MMBtu = 1.055×10^6 kJ)
MPMS	Multi-period, Multi-state
MW	Megawatts
MWh	Megawatt hours (1 MWh = 3.6 GJ)
NSPS	New Source Performance Standard (1971)
SAIC	Science Applications International Corporation
SO_2	Sulfur dioxide
NO_x	Nitrogen oxides
RNSPS	Revised New Source Performance Standard (1979)
SAS	SAS Institute, Inc., developer of a series of data analysis and management packages for the computer
SIP	State Implementation Plan
URGE	Universities Research Group on Energy
US	United States
XMP	FORTRAN based linear programming package

ACKNOWLEDGEMENT

Modification of the Advanced Utility Simulation Model was directed by EPA and performed by Science Applications International Corporation, Inc. at its McLean, Virginia office with substantial efforts contributed by its two subcontractors, RCG/Hagler, Bailly Inc. of Boulder, Colorado and E.H.Pechan & Associates, Inc. of Springfield, Virginia.

RCG/Hagler, Bailly, Inc. modified the Finance Module and contributed a written report of their work. Work performed by Bruce Larson is incorporated into the discussion in Chapter 6.

E.H.Pechan & Associates, Inc. modified a number of elements of the AUSM state model. These include the Capacity Planning Module, the Dispatch Module, the control program, and various report writers. This work is incorporated into the discussion in Chapters 2 and 3. Persons that contributed to this effort include Mike Andreassi, Phil Childress and Suzy Rothschild.

1 INTRODUCTION

The state model component of the Advanced Utility Simulation Model (AUSM) has been run a large number of times since it was delivered in November, 1984 by its developers, the Universities Research Group on Energy (URGE). These runs uncovered a number of coding errors and identified needed upgrades. This document describes revisions made to each of the AUSM State Level Model modules since URGE delivered the initial AUSM Model (Version 1.0) to the U.S. Environmental Protection Agency (EPA) in November 1984.

In general, the errors detected could only have been found through a rigorous program of testing and evaluation, such as the one carried out by the Science Applications International Corporation research team under direction from EPA. The efforts made to correct coding errors are briefly described in Appendix C and are separately documented by source code comments.

Model upgrades, which expand the coverage and usefulness of AUSM, are described in this document. Every module of the State Level Model has been changed in some way. For the most part, these changes incorporate the following:

- more knowledge about technical and demand factors affecting electric utility operations and their generating and emissions control equipment;
- changes in external factors, such as new tax requirements and financing trends; and
- methods in which users wish to run the model, and user information needs.

Additional model upgrades are being made as of this writing. The last chapter describes several of these. However, they are not fully documented in this volume.

Figure 1 is a block diagram of the State Level Model that shows the function of each module. Each of the six modules is executed sequentially for each year. The model's operation is repeated for each of the 48 contiguous U.S. states. Two modules, the control program and the report writer, are not shown in Figure 1. Changes to these modules are documented in the source code rather than this volume because they reflect changes necessitated by modification of individual modules or correction of errors in the URGE version.

DEMAND module changes, described in Chapter 2, were:

- Up to thirty exogenous end user growth rates can now be used in place of the original five rates.

- The revenue requirement adjustment factor has been set to 1.0 in place of its previous value of 0.8 to allow full recovery of costs by electricity rate adjustments.

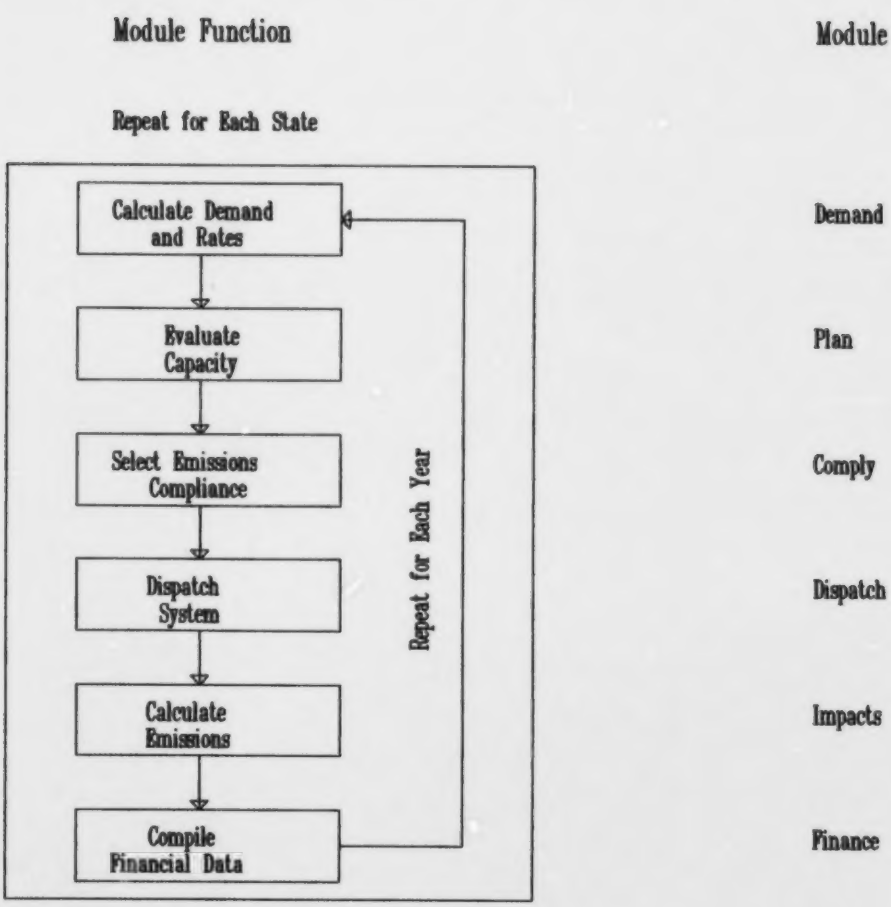
- Historic interstate electricity transfers are used for 1980 to 1985 to help calibrate the model to existing electricity transmission patterns.

PLAN module changes, described in Chapter 3, were:

- Maximum capacity factors and unit availabilities were made scenario dependent instead of data dependent.

- Lifetimes of existing units were made data dependent instead of scenario dependent.

Figure 1. The State Level Model



- Advancing or deferring planned oil-to-coal conversions was eliminated.

- The capacity needs test, which determines when new units will be constructed, was revised.

COMPLY module changes, described in Chapter 4, were:

- Emissions factors were revised to agree with AP-42.

- The assumption that all units added after 1980 are RNSPS units was relaxed to allow known SIP and NSPS units coming on line after 1980 to comply with the less stringent NSPS emissions regulation.

- The LIMB algorithm was revised to reflect the latest cost and performance information available from EPA.

DISPATCH module changes, described in Chapter 5, were:

- The load duration curve (LDC) used to specify load constraints was modified to agree with actual load patterns and to account for interstate transfers.

- Time dependent emissions constraints for SO_2, NO_x, and TSP were added to enhance policy applications.

- Minimum capacity factors were added for some technologies to reflect dispatching of units to meet hourly and daily peak loads and to reflect minimum capacity utilizations resulting from unit turn-down ratio operational constraints.

- The latest version of XMP was added to improve solution of the dispatch linear program.

FINANCE module changes, described in Chapter 6, were:

- Tax treatment was enlarged to include the latest federal regulations.

- The cost of capital was made dynamically dependent on financial condition to relieve the assumed infinitely elastic supply of capital.

- Dividend payment calculation was refined to make payments more realistic.

No significant changes were made to the IMPACTS module. Some of the ongoing changes to the State Level Model, which are described in Chapter 7, are:

- Addition of a SAS-based relational data base capability to allow ad hoc aggregation of results and direct comparison of the results of any two runs.

- Extension of the state model simulation period to allow simulations beyond 2010.

- Expansion of the number of national loop technology categories from 10 to 20 to add the ability to analyze the potential changes in electric generating technology types over a long period of time.

2 DEMAND MODULE

The Demand module determines information for other AUSM State Level Model modules. Generation and peak load demand for the dispatch module, total revenue and net transfer cost for the financial module, and generation and peak load projection levels for the capacity planning module are determined.

2.1 Module Description

Demand Module functions include the following:

- o calculation of demand by end use sector from either user supplied growth rates (exogenous mode) or internal demand equations (endogenous mode);
- o calculation of a two part tariff (customer charge plus marginal price of electricity);
- o calculation of total revenue from sales and price information; and
- o forecasting demand for use by the Capacity Planning Module.

The Demand Module can be run in two modes; an exogenous mode and an endogenous mode. When run in exogenous mode the Demand Module begins by calculating 1980 demand and generation from exogenously specified electric demand growth rates supplied by the model user. Demand for subsequent years is calculated by using state-specific annual rates of change supplied by the user. In the endogenous mode, electricity demand is affected by electricity price-demand elasticity

functions. The electricity rates are calculated from revenue requirements developed from the preceding year's operations. These are provided by the Finance Module.

Rates are calculated for each end use sector as a two part tariff. Revenue requirement is used to adjust rates and provision was made in the original version for less than full pass-through of cost increases.

Total revenue is calculated from prices (rates) and the quantity of electricity sold. Since rates originate from cost calculations made by the Finance Module, there is no danger of separating revenues from costs.

The Demand Module also forecasts demand for the coming years at each year of the simulation. This information is used by the Capacity Planning Module to evaluate system size and make-up. If there is enough existing and planned capacity to meet demand, no changes are made to the system. If, however, there will be insufficient capacity, construction schedules are advanced and/or augmented. Conversely, it is possible to defer construction in the event of forecast excess capacity.

2.2 Modifications to the Demand Module

There were two fundamental changes to the Demand Module: the adjustment factor which converts revenue requirement changes to rate changes was set to a value of 1.0 to prevent perpetual financial loss and the module was extended to recognize 30 annual growth rates in place of the original 5 rates. In addition, data were developed for actual interstate transfers and annual growth rates for 1980 - 1985 as part of the calibration program.

The AUSM base year is 1980 and each following year is a simulation year. Demand and interstate transfer levels are known for the years 1981 to 1985. Actual growth rates and actual interstate transfers were inserted into the model to

ensure that the model agrees with reality for known years. The effect was to cause emissions simulations to be accurate for these years.

2.2.1 Modification of the Rate Adjustment Factor

The Demand Module contains an adjustment factor designed to simulate regulatory lag. Originally, this factor was intended to allow only a user specified fraction of fuel cost increases to be recovered in the allowed price of electricity. This factor was implemented in a way which would never allow full recovery of fuel cost increases and would eventually result in insolvency. The factor was reset to 1.0 to reflect total recovery of fuel cost increases in utility rates.

Reason for the Change

Sector electricity prices are calculated from a two part tariff which includes an adjustment factor intended to represent regulatory lag. The marginal tariff component is given by:

```
PRICIN(2,NS) = PRICIN(2,NS) + ADJF * FPESC
```

where:

PRICIN(2,j) = marginal price for the jth end use sector,
NS = end use sector,
ADJF = adjustment factor (<= 1.0), and
FPESC = fuel price escalation (dollar/MMBtu).

The original version of the Demand Module set ADJF to 0.85, which has the effect of excluding fifteen percent of all fuel price increases from the marginal price of electricity. In consequence, utilities could never recover all of their fuel cost increases. Eventually, cost would exceed price. In fact, this error was

detected during an early review of financial outputs, when costs/revenue streams failed to come into agreement.

Description of the Change

ADJF was set to a value of 1.0 via an assignment statement. Although this approach does not fully capture the intent of the Demand Module developers, it does eliminate the problem of forcing cost to exceed price. Further review of the role of the module in AUSM indicates that there is no a priori way of determining how state regulators will respond to requests for rate rescheduling due to fuel cost changes. The module was revised to effectively allow recovery of these costs in rates allowable in the next year.

Thus, setting ADJF to 1.0 does not entirely eliminate AUSM's treatment of regulatory lag. Lag is simulated by the annual simulation itself, which adjusts marginal prices charged in the current year by cost increases experienced during the previous year. This procedure emulates traditional use of a prior test year (as opposed to a future test year).

2.2.2 Modification of the Number of Growth Rates

The number of growth rate periods was expanded from the original five, multi-year rates to a maximum of 30 rates.

Reason for the Change

Originally, the Demand Module recognized up to five annual growth rates, each applying to a user-specified period of one or more years' duration. Modelling

a 30 year period would result in an average period length of 6 years, which is long enough to mask any cyclical change or change due to regulatory initiative. This level of sensitivity was not considered to be adequate for scenario runs of the model.

Description of the Change

Data Group 17 was modified to accept up to 30 growth rates. Each may apply to one or more years, as previously. Refer to the source code and example state model inputs for formats.

3 CAPACITY PLANNING MODULE

The Capacity Planning Module is responsible for advancing or deferring scheduled capacity additions and/or augmenting the construction schedule in order to ensure adequate generating capacity and limit excess capacity. It was modified by changing the test which determines the need for construction rescheduling/augmentation and by changing the standard sizes of units which are added to construction schedules.

3.1 Module Description

The Capacity Planning Module plays two different but related roles in the State Level Model depending on whether the national loop has been run: If the national loop has been run for more than about 10 years into the future, the announced unit inventory (file E5A) will have been augmented to include units in addition to those which utilities have scheduled for construction. In this situation, the module's chief function is refinement of the construction schedule by advancing or deferring the on-line dates of units tabulated in E5A. If, on the other hand, the national loop has not been run, the module will assume chief responsibility for augmenting the list of announced units in E5A in addition to rescheduling construction.

When units are added by the Capacity Planning Module, they are added in standard sizes. These sizes vary from state to state and are a user input. For example, a small state like Rhode Island would typically add coal-fired units in increments of less than 300 megawatt (MW) while a state like Virginia might add in 500 MW increments. As originally designed, this module used the same default size for each state. In consequence, small states tended to build units which were completely out of proportion to the size of the load they served.

3.2 Modifications to the Capacity Planning Module

Although there were numerous modifications to the source code itself, two substantive changes were made: the capacity needs test and adoption of standard sizes for base load units.

3.2.1 The Capacity Need Test

Available capacity is compared to demand each year and for up to 11 future years to determine whether sufficient capacity exists. Results of this capacity needs test triggers advancement or deferral of construction. The test was modified to render it less sensitive than originally designed.

Reason for Change

Two tests compared projected baseload and peak demands with available capacity, which is defined differently for each of two tests. The base load test compared the total energy which could be generated by existing units with demand using the maximum annual availability to calculate total energy. Availability was used in the peak load test instead of maximum capacity factor. If both tests showed that the state could meet both base and peak loads, no new units were built. On the other hand, if either test failed, construction of scheduled units was advanced and/or units were added to the construction schedule.

When either test failed, construction schedules were advanced in such a way that the generating technology mix came closer to the ultimate (ideal) mix. This mix was exogenously specified before the national loop became available. With addition of the national loop, the mix is an endogenous output from the national

loop. So, failing the peaking test could, under the original design, result in addition of a baseload unit and visa versa.

Description of Change

The needs test was modified by adding a tolerance factor which requires that demand exceed supply by a user-specified fraction to make the test less sensitive. Construction schedules are only advanced (or units added to the schedule) if:

(projected demand) > (1 + X) * (available capacity)

where X is the tolerance factor (for 0 <= X < 1.0). Typically, X values of 0.02 are used, implying that excess demand must exceed 2.0 percent.

3.2.2 Standard Unit Sizes

Each of the twenty-four technologies which can be added to existing generating equipment inventories is added at a fixed size. AUSM does not have the ability to calculate the optimum size of each new unit, although it does calculate the optimal total capacity. Standard unit sizes were changed from default values applied equally to all states in a given scenario to state-specific values, unique to each specific state in a given scenario.

Reason for Change

If a new unit was scheduled for construction, the old version of the module used scenario-specific unit sizes and other attributes. For example, if Connecticut

and Rhode Island were two states run under control of the same scenario directives file (file E8), units added by either state would be the same size and have the same attributes (cost, heat rate, availability, etc.). For example, both Connecticut and Rhode Island would add 1,000 MW coal-fired units. In consequence, average capacity factors for Rhode Island would have been too low until demand caught up with supply. Clearly, Rhode Island would prefer to add smaller units than Connecticut, which would not have been possible under the original design.

Description of Change

State specific new unit sizes were substituted for scenario specific sizes. Examples of the new state specific unit sizes are provided in Table 1. A complete listing of the unit sizes selected for each technology category in each state is given in Appendix D.

The following are suggested as standard unit sizes for baseload units. User-specified sizes substituted for the values shown below.

Technology Category	Prime Mover	Capacity (Megawatts)
1	Turbine	150
2	Turbine	150
3	Turbine	150
4	Hydro	667
5	Steam	500
6	Steam	500
7	Steam	500
8	Steam	500
9	Combined Cycle	220
10	Combined Cycle	220
11	Combined Cycle	220
12	Combined Cycle	500
13	Combined Cycle	500
14	Combined Cycle	1000
15	Turbine	1000
16	Nuclear	1100
17	Exotic	500
18	Exotic	500
19	Hydro	200
20	Combined Cycle	1000
21	Other	50
22	Exotic	10
23	Exotic	100

Table 1. Typical New Unit Sizes

4 POLLUTION CONTROL MODULE

Least cost methods for complying with air emission regulations are determined within the Pollution Control Module. Calculating simulated emissions of SO_2, NO_x, TSP, and solid waste products relies on a complex set of decision rules which consider unit attributes (firing type, size, etc.), economic parameters (capital cost, O&M expense, etc.), fuel price, and scenario specifications. Emissions factors were corrected and the routine which calculates the cost of the lime(stone) injection multi-stage burners (LIMB) option was modified to reflect the use of lime hydrate rather than limestone sorbent.

4.1 Module Description

The comply module is the pollution control component of the Advanced Utility Simulation Model (AUSM). Its function is to determine economic, environmental, and energy impacts of air pollution control regulations pertaining to new and existing coal-fired power plants. It is based on selecting the least cost means of complying with specific emissions standards.

Three types of analytical models go into making up the comply module: 1) system performance models, 2) economic cost models, and 3) decision criteria models. The system performance models determine unit level energy flows, mass flows, and key design parameters for pollution control systems. The economic models determine the capital costs and annual revenue requirements of various pollution control options/combinations. Finally, the decision criteria models determine the least cost combination of alternative fuels, fuel blends, and control technology options which comply with unit-specific air pollution emission regulations.

Pollution control systems addressed by this module pertain to sulfur dioxide emissions (SO_2), nitrogen oxide emissions (NO_x), total suspended particulates (TSP), and solid wastes. The systems specific to these pollutants which have been modeled are listed below.

1. Sulfur Dioxide Removal Systems
   - Wet limestone scrubbing (with or without forced oxidation)
   - Dry lime scrubbing (spray dryer)
   - Lime injection multistage burners (LIMB)[1]

2. Nitrogen Oxide Control Systems
   - Low-NO_x burners
   - Overfire air
   - Lime injection multistage burners (LIMB)

3. TSP Removal Systems
   - Cold-side electrostatic precipitator
   - Hot-side electrostatic precipitator
   - Fabric filter (baghouse) collector

4. Solid Waste Disposal Systems
   - Ponding
   - Landfill

Updates or enhancements relating to some of these systems are the subject of the remainder of this section.

---

[1] The original version of the AUSM used limestone, not hydrated lime and was injected through the burners, not into the flue gas duct.

4.2 Changes

Changes were made to three areas within the comply module -- NO_x emissions factors, post-1980 NSPS/RNSPS differentiation, and the LIMB systems cost and performance algorithm.

- NO_x emissions factors were revised to agree with the AP-42 estimates.
- The assumption that all units added after 1980 are RNSPS units was relaxed to allow those units known to be SIP and NSPS units to retain their compliance requirements.
- The LIMB cost and performance algorithm was updated to reflect the latest cost and performance information available from EPA.

Details of these changes are discussed individually below.

4.2.1 NOx Emissions Factors

Review of the module during testing of AUSM revealed that indices used to identify wet and dry boiler bottom type were transposed in the original URGE version of the functions NOXIDX and FLYIDX. To correspond to the boiler bottom type defined in the unit inventory and by other pollution control components in the code, type 2 was redefined to represent dry bottom boilers and type 1 to represent wet bottom boilers in the NOXIDX and FLYIDX functions.

Further investigation of these functions and their corresponding data file revealed that the NO_x emissions factors delivered by URGE could not be mapped directly to AP-42. Since AP-42 reports NO_x emissions factors accepted by EPA,

this inconsistency had to be remedied. Coal NO_x emissions factors were adjusted to change their units to lb NO_x/MMBtu. These factors were derived from the AP-42 assuming generic coal heating values of 11300 Btu/lb for bituminous and sub-bituminous coals and 7024 Btu/lb for lignite.

Since the units corresponding to the NO_x emissions factors were changed, any code which accessed these emissions factors was adjusted to ensure that correct units resulted from the calculation. Typically, this meant removing the higher heating value (HHV) term from the emissions variable calculation, as was done in the subroutine COMPLY and the functions NOXPBM and FREMN.

4.2.2 Post-1980 NSPS/RNSPS Differentiation

In 1971, EPA established New Source Performance Standards (NSPS) for electric utility steam generating units, and in 1979 revised these standards (RNSPS) to require a percentage reduction in emissions. Originally, the AUSM model defined any unit coming on line after 1980 as an RNSPS unit. This inadvertently required some SIP and NSPS regulated units to comply with the more stringent RNSPS emissions standards. Since information now exists on units coming on line between 1980 and 1985, the code and data files were changed to allow SIP and NSPS units to retain their less stringent emissions standards, when applicable.

Changes were made to the E5 and E5A data files and to the subroutine COMPLY. The data changes involved redefining the flags which represent SIP, NSPS, and RNSPS units. Originally, a 222 represented any unit which came on line after 1980 (whether SIP, NSPS, or RNSPS). This has been changed as follows. A 333 identifies RNSPS units, a 222 identifies NSPS units, and a 111 represents SIP and other units. The code was changed in COMPLY such that the emissions standards were defined properly for each of these regulatory categories.

4.2.3 LIMB System Cost Algorithm

When URGE delivered the AUSM to EPA in 1984, inclusion of the LIMB system as a pollution control option was a technology still in the research and development stage. Consequently, it did not have the extensive basis the other control systems had when its cost and performance algorithm was developed. To address this deficiency, the LIMB algorithm was completely revised to incorporate the latest cost and performance information available to EPA. Costing of both new and retrofit systems were addressed and retrofit factors were revised.

The revised LIMB cost algorithm included new equations for calculating LIMB operating characteristics, capital costs for system components, system upgrade costs, new retrofit factors, and new ceilings on removal efficiency. Variable cost equations have not been altered and are still based on the level of sorbent required. The sorbent, however, has been changed from limestone to lime, and its cost has been adjusted accordingly in the scenario file.

The Ca/S ratio calculations were based on stoichiometric relationships, an analysis of calcium utilization data and a regression analysis of furnace SO_2 removal information from the Edgewater LIMB demonstration test facility.[2] The LIMB performance algorithm is applicable to all coal types. The algorithm limits the furnace SO_2 removal efficiency to a maximum of 80 percent to avoid extrapolating significantly beyond the actual Edgewater program test data. With an additional estimated reduction of 25 percent of SO_2 from the furnace due to the use of duct humidification, the maximum total SO_2 removal is limited to 85 percent by the algorithm. In addition, the maximum Ca/S ratio is limited to be $\leq$ 4.0 to stay close to the boundaries of the Edgewater test conditions. Until higher Ca/S ratio test data are available, projections of performance at a Ca/S ratio > 4.0 are uncertain. More than 88 percent removal may be achieved on high sulfur coals (i.e., $\geq$ 3.0 percent sulfur) with the LIMB technology, but these conditions have not as yet been tested. As more performance data become

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[2] Memorandum from Larry G. Jones, EPA, Research Triangle Park, N.C. to Ron Capone, SAIC, McLean, Virginia, March 1, 1988.

available from the LIMB test program, the algorithm will be updated. The current LIMB algorithm used in AUSM is described in detail in Appendix C.

5 DISPATCH MODULE REVISIONS

The Dispatch Module allocates the demand for electricity among the available generators. Determination of fuel use and estimates of emission for each unit is provided by solving for the least-cost technology mix.

5.1 Introduction

Several key revisions to the Dispatch Module have been undertaken since URGE delivered to the U.S. Environmental Protection Agency (EPA) the original version of the Advanced Utility Simulation Model (AUSM) in November of 1984. Major, substantive changes made to the Dispatch Module are described in this report; documentation of minor changes is available in the comments of the on-line Dispatch Module source code. Examples of major changes include implementing new algorithms, reconfiguring module architecture, adding new data groups, or changing module logic. In most cases, these changes were undertaken to correct Dispatch Module deficiencies found as a result of extensive testing and analysis conducted by SAIC and its subcontractors.

This chapter is divided into two main sections. First, a brief description of the role of the dispatch module in the AUSM is presented in section 5.2. The second section contains two parts: (a) an outline of key deficiencies found in the original construction of the dispatch module and (b) a description of the technical approach used to correct these deficiencies. Some of the main changes to dispatch module discussed in the second section concern the construction of load duration curves (LDC's), the emissions constraint policy options, the capacity utilization of generating units, and the introduction of the new XMP FORTRAN-based linear program (LP).

5.2 Module Description

The Dispatch Module is a key component of the AUSM because it determines fuel use and emissions estimates for individual units within a state. Estimates are derived from a FORTRAN based linear program which selects the best utilization of individual generating units within a state based on two factors: the goal of the user and a set of predetermined information. This information includes the level of electricity demand passed from the Capacity Planning Module; the amount of existing and announced generating capacity available to meet that demand; and characteristics about individual units (expected lifetimes, variable costs, emissions factors, etc.).

AUSM users may select different objectives used in developing the optimal solution. One of two objectives may be selected: cost minimization or least emissions dispatch. Though default runs of the AUSM typically employ cost minimization objectives, users may specify scenarios with minimum emissions objectives.

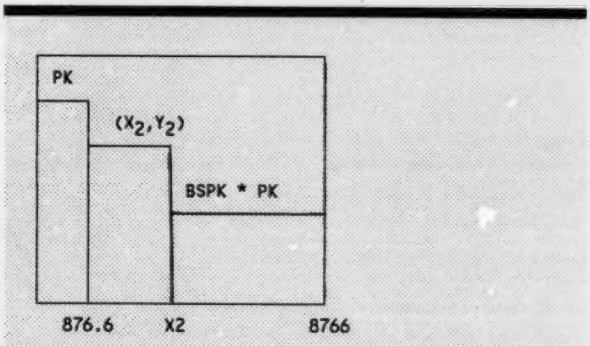
5.3 Dispatching Module Revisions

Major revisions to the Dispatch Module methodology are summarized in this section. This revised dispatching methodology evolved as an effort to address the major deficiencies of the November 1984 version so that testing of other parts of the model could begin. While the URGE version of the Dispatch Module was mathematically correct, there were some deficiencies in its construction. These deficiencies can be subdivided into three broad categories: LDC development, emissions constraint flexibility, and capacity utilization. Dispatching results generated by the AUSM misrepresented actual aggregate utility behavior because of flaws in each of these categories.

5.3.1 Load Curve Representation

One of the most serious flaws in the original version of the Dispatch Module was the treatment of load duration curves. Several aspects of developing load duration curves were modeled incorrectly. Some of these errors included: using nearly identical load patterns in each state; allocating too much energy to the peak segments of the LDC; and calculating baseload LDC segments with extremely low system load factors. All of these problems are discussed in greater detail below.

Initial testing of the Dispatch Module focused on whether changes in maximum capacity factors for existing coal units affected emissions levels or fuel use mixes. These variables, it turns out, were quite insensitive to changes in capacity factors. These counter-intuitive results were attributed to the form of the load-duration curve generated by Dispatch. Although the three segment vertical load-duration curve was formed using two input parameters, only one parameter, the annual average load factor, determined its shape.



where:

X_1 = 876.6
Y_1 = PK
X_2 = (EG - BSPK * PK * 8766) / (PK * (1 - BSPK))
Y_2 = EG /8766
X_3 = 8766
Y_3 = BSPK * PK

Figure 2. Type 1 State Load Duration Curve

A limitation of the original Dispatch Module was the use of an essentially identical load pattern in each state. Each load pattern was characterized by an extremely low level of baseload electricity demand. Load patterns vary significantly from state-to-state because of regional differences in weather conditions and categories of load demands. So, regionalized LDC formulations were incorporated into both the merit order and the LP subroutines of the Dispatch Module.

Formerly, both load curve formulations produced baseload segments with extremely low values. These formulations were inaccurate compared to historical load data. In fact, large utilities often have high system load factors. Additionally, Southern and Gulf coast utilities have prominent peaks because of periods of high residential air conditioning use. The first load curve formulation has a single breakpoint which is calculated from average load factor and state-level base-to-peak ratios. The second load curve formulation also has a single breakpoint at 1600 hours for the hot weather-air conditioning oriented states.

Initially, the peak load segment accounted for 25 percent of the total hours. The baseload segment of the LDC, however, attained zero or negative values for load factors near 50 percent because of the high fraction of peak load hours. Reducing the peak load segment to ten percent of the number of hours in a year corrected the problem.

States were divided into two categories with a "breakpoint" that represents an approximation of the peak load/intermediate load ratio. Type "2" states have prominent peak loads; type "1" states do not. The "breakpoint" for type "2" states was set to 1600 hours while type "1" states calculate the "breakpoint" as peak load times the system load factor. The three segment load-duration curve (LDC) was developed so that the sum of generation for the baseload, intermediate load, and peak load would approximate the area under the proxy LDC. Examples of both types of curves appear in Figures 2 and 3.

The source of information for these two load curve formulations was the Federal Energy Regulatory Commission (FERC) Form 12 load curve data reported by utilities to the Department of Energy (DOE). FERC Form 12 load data for 1981 were analyzed for selected representative utilities for each state. Type "1" versus type "2" states were determined heuristically from graphical representations of the extrapolated LDC for each representative utility.

Note that in the Type 2 curve:

$$Y_2 = 2 * XLF * PK - \frac{(PK * X_2)}{8766} * (1 - BSPK) - BSPK * PK$$

which is the same as

$$Y_2 = 2 * XLF * PK - \frac{(PK * 8766 * (Y2))}{8766 * (PK)} * (1 - BSPK) - (BSPK * PK)$$

Therefore,

$$Y_2 * (1 + 1 - BSPK) = 2 * XLF * PK - BSPK * PK$$

or

$$Y_2 * (2 - BSPK) = PK * (2 * XLF - BSPK)$$

Finally,

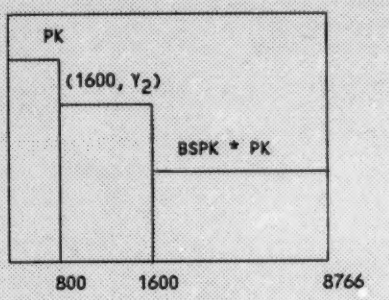
$$Y_2 = PK * \frac{(2 * XLF - BSPK)}{(2 - BSPK)}$$

Variable definitions:

BSPK	Base-to-peak ratio
EG	Energy demanded in megawatt hours
PK	Peak load in megawatts
X_i	Horizontal coordinates forming the edges of the Argonne load trapezoids.
XLF	
Y_i	Vertical coordinates forming the edges of the Argonne load trapezoids.

Type "2" LDC's have two prominent features. First, the LDC becomes vertical at the point labeled PK*BSPK or at 8,766 hours (one year). BSPK equals a fraction over the closed interval [0.30, 0.60]. Originally, just five states had BSPK values outside this range. The kink in the curve at HR hours and at load P is the second prominent feature. HR equals either 876.6 or 1,600 depending on whether the state type is "1" (generally northern tier states) or "2" (generally

southern tier states). The derived system load factor, which can equal any value within the interval [BSPK, 1.0], is P. Hours break-points are fixed for type "2" states; these values are calculated from total energy and the parameters listed above for type "1" states. Accordingly, the hours break-points usually change from year to year and from state to state with type "1" LDC's.



where:

Y_1 = PK - ((Y_2 - PK) / X_2) * X_1
X_1 = 800
X_2 = 1600
XLF = EG / (PK * 8766)
Y_2 = (2* XLF* PK)-(PK* X_2/ 8766)
* (1 - BSPK)-(BSPK * PK)
X_3 = 8766
Y_3 = BSPK * PK

Figure 3. Type 2 State Load Duration Curve

5.3.2 Emission Constraint Change

As a policy tool, the AUSM offers users the flexibility to implement a wide array of scenario specifications, including emissions reduction strategies. In the old version of the Dispatch Module AUSM users could set state-specific emissions caps for SO_2, NO_x, and TSP. While this allowed users to undertake specialized analyses of emissions reduction initiatives in individual states, there was a drawback. Once users had defined an emissions cap and the corresponding year in which the cap was to take effect for a given pollutant, this restriction was binding for the rest of the simulation. In turn, this limitation presented two difficulties. First, future growth in the demand for electricity could result in dispatching infeasibilities since the operation of some units might be restricted by emissions. Second, it was difficult to model some emissions reduction policies based on gradual or "phased-in" emissions compliance targets.

Operation of the AUSM has been changed in two ways because of modifications to both the dispatching algorithm and to the architecture. On the one hand these changes have greatly reduced the possibility of achieving infeasible results in

executing the linear program XMP. At the same time, users may now flexibility tailor model capabilities to solve more "realistic" policy scenarios.

Dispatching infeasibilities resulting from implementing emissions reduction scenarios are less likely now. Increasing the number of time periods in which emissions caps can be instituted has lessened the possibility of violating emissions constraints resulting from growth in the demand for electricity. Further, "escape valve" variables have been added to the dispatching module so that mathematical infeasibilities caused by users applying emissions maxima which are too stringent can be avoided. Instead of aborting, the model will now automatically request an emergency power purchase (at a very high cost per pound of emissions reduction avoided) and a flag is written to the AUSM emissions output file (R505) informing the user that emissions maxima were too strict. Though the run should probably be executed again, users have better information at their disposal to set new maxima.

Invoking the new emissions constraints is simple. If state-specific scenario GETSCN variables 528 (SO_2), 529 (NO_x), and 530 (TSP) are set to "-1.0" in the Regional Scenario Directives file (E8) then the right-hand side constraints for these variables should be read from the external state emissions file (STEMAX). If the values for these variables are in turn "-1.0" then the constraints are set free by installing large numbers as the RHS entries. Finally, if the emissions level for variables 528-530 is not set to "-1.0", then the model will operate just as it has in the past.

5.3.3 Capacity Utilization/Calibration Effort

Imprecision in simulating realistic aggregate annual unit dispatching decisions that reflected day-to-day constraints on unit dispatching was the chief flaw of the original Dispatch Module. Some of the factors contributing to this problem included: operating some units at extraordinarily high capacity factors while not using other available units at all; using very low maximum capacity factors

for baseload coal units; and building too many peaking units. A number of solutions to these problems were investigated and later implemented.

To improve capacity factor distributions for all units, unit-level, annual minimum capacity factor distributions for all units were specified by adding bounds to all the dispatch variables. Minimum annual capacity factors are contained in the state model Capacity Factor (CAPFACTS) data file (see Appendix A). These minimum capacity factors reflect several constraints on day-to-day utility operations. For example, base load coal-fired unit annual capacity factors reflect unit turn-down ratios and the minimal use of some of the more costly to operate units to meet spinning reserve requirements. In the case of simple cycle gas turbines, however, the minimum capacity factors reflect only historical usage. Extensive testing revealed that the best results are obtained when the bounds are placed on dispatch variables for all load segments.

In another attempt to improve the effectiveness of the AUSM in simulating aggregate utility dispatching behavior, a market-sharing algorithm was devised to distribute generation among units more evenly. The market-sharing algorithm reallocates coal plant operations to units based on variable cost. Coal-fired generation is met by coal plants operating between their maximum and minimum coal capacity factors (i.e., the LP constraint values), collectively. Final capacity factors for individual plants, however, are adjusted between the lowest and highest capacity factor. To achieve a more realistic representation of utility operations more expensive plants are operated at lower capacity factors; less expensive plants are run with higher capacity factors.

The market-sharing approach was ultimately removed from the model for two reasons. First, using this algorithm resulted in only small improvement in the distribution of capacity factors and the accuracy of model results for historical years. Second, this approach is heuristically ad hoc.

Improperly restricting coal unit capacity factors was a critical problem with both original dispatching methodologies. All individual coal unit capacity factors were limited to a maximum value of 0.567 in earlier URGE formulations

(both LP and merit order). In fact, this was the average capacity factor in 1980 for coal units in excess of 400 megawatts between 2 and 16 years old. Testing revealed that some states could not meet demand in 1980 even if all available generators were operated at the 0.567 maximum capacity factor. In the AUSM version delivered by URGE, the 0.567 maximum was relaxed only for coal units known to have operated above this capacity factor in 1980. Though the demand for electricity could now be met in each state, only the units which operated above the 0.567 capacity factor in 1980 were permitted to operate at higher than average capacity factors in future years. This restriction was removed. Individual units are now permitted to operate up to the predefined maximum capacity factor in each state. Maximum capacity factors are specified to reflect unit availability limits.

Previous incorrect specification of the load curve for both dispatching methodologies, merit order and LP, created another problem. Under the previous LDC formulation oil and gas turbine and oil and gas steam units were dispatched too much relative to coal units. Simply adjusting the LDC formulation to establish less peaking and cycling load dispatching relative to baseload coal dispatching, however, only exacerbated the problem discussed above -- coal usage was already constrained by a 0.567 maximum capacity factor, particularly in high demand growth cases.

These problems were solved by adding state-specific capacity factor constraints for various plant categories based on data derived from selected historical plant usage information. This permitted individual units to operate at capacity factors which approach availability, while constraining overall utilization to reasonable values. State-specific capacity factor information for different fuel types were derived from analyses of Federal Power Commission (FPC) Form 4 for the years 1970, 1975, 1980, 1981, and 1983. Capacity factor minima and maxima were based on actual, observed market behavior. Generally, the reported maximum and minimum CF values were used.

- state-specific capacity factor minima were added for coal boilers, oil and gas boilers, and turbines; and

- state-specific capacity factor maxima were added for coal boilers, oil and gas boilers, nuclear boilers, and hydroelectric units.

Subjective decisions had to be made in some cases, however, because of significant variance between the maximum and minimum CF values. Large differences in the values were attributable to a number of factors such as the start-up of a large plant, a coal strike, or extraordinary rainfall. If data were unavailable for a state, data from a nearby similarly configured state were used.

In addition, the code has been revised to obtain maximum capacity factors from the E2, Capacity Planning Data File. This change was made because the maximum capacity factors are part of the scenario specification for many runs. Instead of updating generic unit level data each time a scenario input is modified, users now only need to modify the 24 entries in the E2 Capacity P. .ning Dataset.

Another limitation of the URGE version of dispatch was the lack of controls in dispatching low cost plants, particularly hydroelectric and nuclear units. Unconstrained generation of these units was partly responsible for the unfavorable comparison of AUSM results to historic dispatching data. Calibration of AUSM results to historical data has improved in part because of the implementation of generic capacity factor minima and maxima for all types of units. Unit capacity factor limits, minimum and maximum, for each technology type are listed in Appendix E.

5.3.4 Implementation of New XMP

An updated version of the XMP FORTRAN-based linear programming tool has been incorporated into the Dispatch Module. The latest version now includes double

precision capability and is fully compatible with VS-FORTRAN. Coding changes undertaken to implement the new XMP are documented in the program code.

6 FINANCE MODULE

The Finance Module, which simulates a utility's financial position for each year, was modified by altering tax, dividend, and interest rate calculations.

6.1 Module Description

The Finance Module of the AUSM state model has several important functions:

- assembly of information on capital and operating expenditures,
- calculation of financing expenditures,
- calculation of taxes,
- calculation of revenue requirements, and
- preparation of financial statements.

Revenue requirement is passed to the Demand Module, which establishes rates by end user class and computes total revenue from sales and price. Accordingly, the Finance Module receives information from nearly every other module in the state model and passes information back to the first module (Demand) to initiate the annual recursion process which is a key feature of AUSM.

6.2 Modifications

Three modifications were made to the Finance Module:

- Computation of federal income tax was modified to include new rules imposed by the Tax Reform Act of 1986. The module was further modified to recognize which of three sets of tax rules should apply during a simulation beginning in 1980.

- Calculation of dividend payments was modified to impose stability on dividends reflecting actual utility practice.

- The assumption of infinitely elastic capital supply was removed by making interest rates dependent on financial health.

6.2.1 Modification of Tax Computation

Federal income tax calculation was modified to include the Tax Reform Act of 1986. This modification allows AUSM to select the correct set of tax laws from among the three sets applicable from 1980 forward. Finance module source code, internally kept data, and external data groups are effected by this change.

Reason for the Modification

The Tax Reform Act of 1986 substantially changed computation of corporate taxes. Major changes impacting utilities include the tax rate, tax lives, depreciation schedules, and investment tax credits. There are a few areas covered by the new tax law that are considered significant in general but are not important in modeling utility financial behavior as done in AUSM. These include minimum tax requirements, changes in deferred tax treatment and allowance for funds used during construction (AFUDC) computations.

AUSM's computation base year is 1980 and all of the model's data are based on this date. Therefore, the module must include correct tax computations for all years from 1980 forward. This period includes two major revisions to the tax calculations for a total of three tax laws. AUSM must be able to handle each of the three sets of laws and also be able to choose the correct law.

The federal corporate tax rates from 1980 forward are:

- o 1980-1986 46%
- o 1987 40%
- o 1988-on 34%

These rates apply to all states except Nebraska and Tennessee, both of which are dominated by publicly owned utilities. Their tax rates are effectively zero for all years.

The 1986 tax reform also changed the tax lives of assets, which in turn changes the depreciation schedules. While tax law changes are in general quite extensive, the changes are much simpler for utility assets of concern to AUSM. For utility plant, all assets which had a 10 year tax life now have a 15 year life and assets which had a 15 year life now have a 20 year life. The tax life of a qualifying retrofit pollution control facility was unchanged.

Modifications to Tax Computations

The old version of AUSM read the single federal tax rate from a data group file (DG 60) into the variable FTXRT. DG 60 is a national data group and is only read once for all states. The variable FTXR is used for the actual tax computations and was set equal to FTXRT unless the current state was Nebraska or Tennessee. These states are dominated by public authorities and therefore use a tax rate of zero. The single tax rate was stored in FTXRT for these

states. The revisions to the code require multiple values for the federal tax rate. For this reason, a new variable SAVTXR was used to save the tax rate for public states and FTXRT is now used exclusively to store the long run tax rate.

Two major changes were required to implement new depreciation rules. First, the new depreciation schedules had to be made available to the model. The old schedules were read in from DG 60, the national data group. Because these schedules are still needed by the model and changes to the data groups is very cumbersome, no changes were made to the structure or depreciation schedules within DG 60. The new depreciation schedules have been added in a BLOCK DATA program, named BLOCKA, located at the end of the finance code. (BLOCKA is used for other changes as well.) The new schedules are contained in arrays DP152 and DP201 for 15 year and 20 year lives respectively.

The second major change concerns the transition from the old code to the new code. New depreciation schedules provide less favorable write-offs of new assets. Because of this, the new tax code contains rules that are designed to allow plants that were under construction prior to the change to qualify for the old depreciation schedules, even though the plants are completed after the new code is in effect. These are the "transition rules" in the new law. In general, the transition rules specify that a plant qualifies for transition status if: (1) a binding contract was in effect prior to March 1, 1986; (2) the project is completed before 1990; and (3) half of the total cost was incurred before March 2, 1986. The exact transition rules vary slightly, depending on the exact type of asset.

It is not possible to exactly determine these tests within the AUSM model but given the level of detail required in AUSM, it is not necessary. RCG/Hagler, Bailly, Inc. performed an analysis of transition status for utility plant. That analysis was applied to determine a simple rule for transition status based on the asset type

Asset Type	Number	Year
Fossil Steam	1	1990
Combustion Turbine	2	1989
Hydroelectric	3	1990
Nuclear	4	1990
Transmission	5	1987
Distribution	6	1987
Retrofit Pollution	7	1988

Table 2. Asset Type

and commercial operation date. The year in which each asset type begins using the new law is presented in Table 2.

The series of "IF" statements that determine the transition dates would appear to assign transmission and distribution to a 1988 transition plant. However, these two asset types are actually processed in a separate section of code and the 1987 dates are used correctly.

Finally, the new tax code eliminated the investment tax credit (ITC) entirely. No changes in the AUSM code was required for this change. The ITC rates for each year are inputs from DG 60. DG 60 must be changed to reflect the new ITC rules. In addition, the tax basis adjustment for ITC is changed from one-half the ITC amount in the old tax code to the full amount in the new code. The adjustment follows the date of change described above for transition plant.

6.2.2 Modification of Dividend Computation

Calculation of dividends paid to common stock was modified to provide for stable dividend payments over time, which reflects actual utility practice better than the original procedure.

Reason for the Modification

AUSM originally computed dividends as 15 percent of the prior years retained earnings balance and issued no dividends if earnings for common were negative for the year. Earnings for common is net income minus preferred dividends. Special dividends were issued in situations where internally generated funds exceeded the normal need for these funds. This computation allowed dividends to vary widely from year to year. More importantly, this computation did not properly calibrate the first year dividends for the 1980 base year.

AUSM was tested with Illinois data and these results are used as examples together with national average data. Actual figures are based on major utilities headquartered in Illinois: Central Illinois Light Co., Central Illinois Public Service Co., Commonwealth Edison Co., Electric Energy Inc. and Illinois Power Co. The actual data is taken from Statistics of Privately Owned Electric Utilities 1980 (1).

AUSM originally calculated dividends for Illinois at $128 million. This is based on the 15 percent of prior retained earnings balance, which was $852 million. The actual value for Illinois in 1980 was $392 million in dividends and a $943 million retained earnings balance. The difference in retained earnings balance is probably based on the removal of gas utility impacts to the figures. Three of the utilities also sell gas. Net revenues from the gas portion of these utilities is about 6 percent of total net revenues. The apportionment used for AUSM is not important for this discussion. The difference in the dividends is very important as well as quite striking. The old method of calculation produces results that are wrong by more than a factor of three.

The old method also resulted in wide fluctuations. Dividend yield on book value of common begins at 3 percent and increases to 6.9 percent by 1987. This represents a 12.6 percent increase per year, which does not reflect normal utility behavior.

Modification to Dividend Calculation

The Finance Module was modified to base dividends on the total amount of paid-in capital and a target payout ratio. Paid-in capital is the proceeds from issuing stock. Payout ratio is the ratio of dividends to net income, in other words, the fraction of net income paid to stock holders. Base year dividends are set at a 70 percent payout ratio. Subsequent year dividends are increased or decreased by the ratio of change in the paid-in capital. Further, if the utility

is financially well off, dividends are permitted to increase. If the utility is in bad shape financially, dividends may be reduced.

There are five sections to the dividend sub-module: initialization, stock issuance and retirement, dividend coverage test, income growth test, and calculation of new dividends. Modeling of dividends begins with initialization of various counters, triggers, and ratios relating to growth measurement and accounting for possible need to cut dividends. The growth trigger is the number of years of earnings growth required to justify an increase in dividends. In lieu of specific information, a growth trigger of 2 was used. A target dividend payout ratio of 0.7 is used as a default which can be over-ridden by a user provided ratio. The dividend coverage range sets the level by which earnings must exceed dividend payout to avoid consideration (i.e., increment counter) of a cut in the dividends. It should be set at 0.10 unless other information is available. The cut counter represents the number of years that the dividend coverage ratio can be violated and should be set at 3. The initial dividend payout can be found in the initial data set. It need not result in the target payout ratio, but if it is not, then the growth counter may need to be set greater than zero, indicating some past earnings growth. Once the initial values have been set, the dividend sub-module can be implemented for each year. All transactions are assumed to take place at the end of the year and use current year data.

If new stock has been issued or stock retired during the year, the existing dividend payout must be adjusted to account for dividends on more (less) stock. Ideally, an adjustment would be made in the number of outstanding shares and dividend payout would be adjusted based on number of shares (i.e., new dividend payout would be equal to old dividend payout times 1.0 plus the ratio of the change in shares to old shares). But, implementing this ideal in the Finance Module is not possible because AUSM does not simulate the number of shares of stock. The Finance Module only calculates the value of common and preferred stock, not the number of shares.

Translating changes in common equity to number of shares, requires estimation of the price per share received or paid for the stock, as well as the issuance costs. Estimation of market price for stock is problematic at best and, when this must be done numerous years in the future, probably impossible. Instead, changes in common equity are used as a proxy for changes in number of shares. In order for this to be completely true, the market price of the stock would have to be the same for a current transaction as for all previous transactions. While this is not absolutely correct, it appears to be the best available proxy, given existing data. Under this proxy, total dividend payout would be increased by the ratio of change in common equity to old common equity.

Two tests are used to help calculate present and future dividends payments: the dividends coverage test and the income growth test. Their joint effect is to stabilize dividend payments.

The dividends coverage test, determines whether earnings during the year exceeded the dividend payout (adjusted for changes in stock outstanding, if appropriate) by more than the dividend coverage range. If earnings are close to or less than, the dividend payout, the cut counter (C) is incremented by 1, provided the earnings are within the coverage range. The cut counter is incremented by 2 if the earnings are more than the coverage range below the dividends. The cut trigger allows three years of earnings approximately equal to dividends, or two years of earnings below the dividends, before cutting the dividend to the target payout ratio. Any increase in the cut counter resets the growth counter to zero.

Presuming earnings exceeded dividends, the second test is whether earnings during the year increased, in constant dollars, over the previous year. If so, the growth counter (G) is increased by 1. If earnings did not increase, but stayed the same or decreased less than 2 percent over the previous year, the counter is not increased. If earnings decreased more than 2 percent, the counter is reset to zero.

Dividend payments are calculated by comparing the counter with the growth trigger. If earnings growth is insufficient to trigger a dividend increase

(i.e., the counter is less than the trigger point), the adjusted total dividend payout remains constant. If earnings growth has been sufficient (i.e., the counter is equal to the trigger point) and if the existing actual payout ratio was less than the target, the total dividend payout increases to meet the target dividend payout ratio. The second condition assures that dividends were not decreased if one of two events had occurred. The first event would be if the utility had several bad years where the payout ratio had risen well above the target, followed by enough years of earnings growth to pass the trigger, but that had not recovered its prior position. The second event would be if the utility had issued new stock such that its dividend payout ratio had risen above the target.

The most important data requirement is the target payout ratio. Other data values, such as the growth counters and target bands, are based on user input. Default values are contained in a block data statement for easy user access. Table 2 shows the dividends, net income and retained earnings for investor owned utilities for 1970 through 1985. Ratio 1 is the dividend payout ratio. Ratio 2 represents the old ratio used for dividends. Ratio 2 indicates the old policy was not stable over time. The values were obtained from Financial Statistics of Selected Electric Utilities 1985 (2). These statistics include companies that are solely electric, gas and electric and several companies that are solely generation in nature.

Reported dividends in AUSM include "special dividends" in certain circumstances. This special dividend occurs when the internally generated funds of an utility exceed the normal financing requirements. Essentially, the utility has excess cash for which the Finance Module provides no outlet.

AUSM originally handled excess cash by retiring a combination of debt, preferred and common equity. Retirement was done so as to preserve the desired mix of common and preferred equity and debt. A problem occurred because retained earnings were drawn down as part of the overall reduction. The only way to reduce retained earnings is to pay a dividend. If this occurs often, or in large

amounts, the dividend policy becomes one of liquidating the utility. Dividend yields become inappropriately high.

Several options for resolving the problem were reviewed. The easiest and most obvious would be to reduce only paid-in common equity. In the Illinois test case, however, paid-in common equity would have been reduced to zero. That result is equally inappropriate. The exact option a real utility would use depends on the specific situation of the utility. The goal would not necessarily be to keep the same capital structure, as cash rich companies would be less susceptible to the requirements of the capital markets. The options would include:

- o retire high cost debt,
- o buy securities to be sold when cash is needed,
- o make investments for additional income,
- o buy back common stock,
- o buy back preferred stock,
- o diversify into new, non-utility business,
- o pay a special dividend, and
- o retire low cost debt.

Many of these options are eliminated by the structure of the Finance Module. For example, since all debt is averaged into one lump sum, the option to retire only the high cost issues is not possible. Also, a utility in a cash rich position will likely forecast the extent of the surplus cash flow for many years in the future. If the situation is likely to be temporary, the decisions will be much different than if the situation is likely to persist. AUSM does not have the ability to look into the future in this way.

As mentioned above, the Illinois and Wisconsin test cases produced extreme amounts of surplus cash. In the case without the modified dividend policy above, (which exacerbates the problem), the Illinois utility reached a maximum capitalization of $24,692 million in 1987. By 1998, when construction begins

again, capitalization is only $13,978. Almost half the equity in the utility has been liquidated. Illinois may be an extreme case.

Careful review revealed that the primary cause is the lack of construction expenditures. Construction expenditures can be divided into six main categories:

- o new generation plant,
- o new transmission plant,
- o new distribution plant,
- o new general plant,
- o retrofit pollution control, and
- o replace, repair or upgrade existing plant.

Expenditures on new generation plant, which is easily identifiable in AUSM, are low in many years because no plant construction is needed. Transmission, distribution and general expense are somewhat vague. A new distribution line could be built for new load or to replace an old line. AUSM computes these plant requirements based on increases in demand. If the estimates of the relationship between sales and new investment includes investments for replacement as well as new facilities, then AUSM properly handles these categories. AUSM also accounts for retrofit pollution control. The last category on the previous list appears to be missing in AUSM. This category is often ignored in financial analysis, usually because estimates of the expected expenditures are very difficult to come by, even though this category is not small.

An estimate of generation plant additions not included in AUSM for 1980 is about $200 million. This is during a period of very constrained financial budgets in Illinois. Although $200 million is small compared to the $1,888 million in construction expenditures in that year, it is comparatively large in later years when new construction is low. The AUSM results for 1995 show total capital expenditures of only $107 million. After increases for inflation and increases associated with additional plants, the $200 million estimate for 1980 may grow to as much as $500 million by 1995. In the Wisconsin case, total capital

expenditures are actually zero one year. A cursory examination indicates that transmission, distribution and general plant additions may also be low.

The above problems with the AUSM do not prevent its use as a policy tool. The financial model serves two purposes in the analysis of control costs: computing revenue requirements and determining the ability to finance retrofit control plant. First, the revenue requirement calculations are not greatly affected by the above problems. The small effect that does occur will have approximately the same impact for all comparative cases. Therefore the difference among cases will be unaffected.

The problem with the surplus cash can have very important ramifications. The existence of surplus cash might lead some policy analysts to favor control policies which are biased toward capital expenditure. Since the excess cash situation is not readily apparent in the outputs, the situation may go unnoticed. One example of this situation would be a case that showed a particular control strategy was impractical because the amount of capital a utility would have to raise in a particular period was excessive. If the utility had just retired an equal amount of capital, or just paid it out in special dividends, the strategy would be wrongly criticized. An experienced analyst should be able to work with these problems. The best solution would be to fix the problem when time and budget permit.

6.3.3 Making the Cost of Capital Dynamic

The Finance Module was modified to vary the cost of debt as a function of the financial health of a utility. Heath is measured by an interest coverage ratio.

Reason for the Modification

Several members of the Massachusetts Institute of Technology peer review team commented on the assumption of infinitely elastic capital supply during their study of the Finance Module. This assumption is embedded in the structural assumption that new financing is available without limit at a user-specified interest rate. In contrast, bond ratings normally determine the interest a utility must pay in order to attract purchasers for new debt. This assumption could bias results of analyzing policies which force capital additions or which provide for a choice between capital investment and incurring expense.

Modifications to Add Dynamic Cost of Capital

Cost of capital as input by the user was increased or decreased in relation to the utilities' financial health. Financial health was measured solely by one interest coverage ratio, COV2. Table 5 shows the premiums that were used. As with other changes, these premiums were placed in a data statement for easy modification. The table shows the premium and approximate Standard & Poor rating for each range of coverage ratio. The rating is approximate because actual ratings are based on several indicators, the range of indicators overlap for each rating and the rating firms apply substantial changes to subroutine R602.

Premiums are based on an analysis of utility bond yields as reported by S&P and Moody's for the period 1946 through 1983. Results of the analysis and data are provided in Table 6. The first page shows the premium on utility bonds over government bonds for several time periods with the average representing the average of all bonds issued over all of the years shown.

The period 1973 to 1983 was selected as the most representative for current use. Final premium is based on the average of the Moody's and S&P premiums. It is interesting to note that within each rating category, Moody's bond yields are

consistently higher than S&P. The standard deviation indicates that the utilities within each rating for S&P are somewhat more homogeneous than with Moody's.

Subroutine R602 required minor changes to print out the new information. Three additional values were added to the Unit 10 write statement near the end of the FINAC subroutine. These variables are RINTM, PRETM and CRET, the rates for new debt, preferred and equity respectively. In addition, the variable IT3, was changed from 71 to 74 to account for the additional three variables. The new variables were added to R602 as well as the appropriate statements to write the variables.

6.4 Descriptions of Variables

Appendix B provides a list of changed and new variables within the AUSM financial module. The descriptions are brief and intended for use by programmers during any future update.

7 MODEL ENHANCEMENT

AUSM is still an evolving tool. Several additional upgrades are planned for the national loop and State Level Model at the time of this writing. These upgrades, the result of the continuing efforts to produce the most effective modeling tool for utility analysis and policy making available today, will be documented later as Version 4.o of AUSM. Key upgrades currently planned are:

- o extension of the state model simulation period from the year 2009 to the year 2040,
- o modification of the unit inventory file and announced inventory file to incorporate newly revised NURF data for 1985, and
- o creation of a unit level SAS-based relational data base capability to permit ad hoc analysis of state model results and comparisons of separate scenario results.

An upgrade is planned for the national loop which expands the maximum number of national loop technology categories from 10 to 20. This upgrade will provide more accurate matching between the national loop and the state model.

7.1 Simulation Period Expansion

The state model currently executes for thirty years over the time period 1980 through 2009. The national loop executes for 61 years from 1980 through 2040 and provides information to the state model in 5 and 10 year increments through 2040. Extension of the state model to 2040 will provide, for example, the

capability to study long range effects of regulatory changes on emission levels and utility dispatching.

The planned upgrade to the state model basically involves re-dimensioning arrays, adjusting loop indices and changing end year references. Although cumbersome programming-wise, the upgrade process is generally straight-forward. Expansion of the state model to 2040 will have no impact on the national loop solution procedure.

7.2 Unit Inventory Modification

AUSM presently operates off of a 1980 base year. National Acid Precipitation Assessment Program (NAPAP) plans designate changing the base year of the model to 1985. Without reworking the model start year, the base year change can be implemented by revising the 1980 start data and calibrating the interim results, 1981 through 1985, to historic data. The reasons for not moving the start year are as follows:

- DEMAND was built on the premise that 1980 would be the base year. Accordingly, all data and equations were developed for that year. Gathering new data and re-estimating equations (using econometric techniques for curve fitting) would be very time consuming and have an extremely uncertain outcome.

- FINANCE uses data developed by pooling financial data for electric utilities operating in each state to create a hypothetical utility. These data are based on financial conditions for 1980. Moving the base year would require redeveloping all financial data, which would be very time-consuming and costly.

- The original URGE plan was to make the choice of base year variable throughout the source code, it is by no means clear that this intention was carried out. Moreover, the 1980 base year may be embedded in the code in subtle ways which are difficult to detect except by extensive testing.

The 1985 National Utility Reference File (NURF) currently under development, will represent the latest information on generating capacity and characteristics. These data represent a significant update to the 1980 NURF. Updating these data presents an alternative to changing the base year from 1980. The current plan is to retain the 1980 base year but upgrade the unit inventories contained in files E5 and E5A (current and announced inventories) by the following approach:

- Current inventories will be updated from the 1985 NURF to reflect new information about units in the inventory for the years 1980 and earlier.

- Announced inventories will be updated from the 1985 NURF to reflect units which came on line between 1981 and 1985.

- The 1985 announced unit inventory will include planned units. Such units will be flagged as are units which have not come on line during 1981 to 1985.

These changes amount to extending the base year to 1985 and avoid changes to DEMAND and FINANCE outlined above.

7.3 Solution Analysis Capability

Two solution analysis features are lacking in the current version of the AUSM: a centralized location for model solution data and a direct procedure to analyze solution sets for two separate state model scenarios. A solution to the initial problem is to rewrite the state model source code to write solution data to a common report format. This would require major reorganization to the existing source code and possibly destroy the modular structure of current AUSM system. A more feasible solution is the creation of a post-processor through SAS that would pull the current solution files into a workable analysis structure.

State Level Model solution files currently do not provide an efficient means of studying the results of changes between model runs. The disaggregated structure of the present solution data file system requires extensive manual reorganization of solution tables in order to create an analysis study. As with the solution to the first problem a centralized SAS dataset will permit the pooling of results for effective analysis. Since the SAS programming language provides an effective tool for organizing and reporting data, addition of a SAS-based relational data base capability will permit ad hoc aggregation and analysis of scenario solutions. Further, this SAS-based system would provide the capability to directly compare the results of two separate scenarios.

7.4 National Loop Upgrade

The AUSM national loop presently utilizes 10 plant technology categories in the linear program. These 10 technology categories are mapped into the 23 categories used in the state model. Expansion of the number of technology categories in the national loop from the present 10 to a maximum of 20 provides for a more accurate mapping of categories to the state model. Although the complexity of the linear program in the national loop is increased through additional breakout of coal types and oil qualities burned by utilities, the

benefit of the added detail outweighs the cost of the larger linear program.

Upgrading the technology categories requires modification to the table generator, capacity additions file and E5A generator, and input file expansion to accommodate 20 technology categories. Modification of the capacity additions file and E5A generator is handled along with the upgrades required to include the 1985 NURF data in the state model, which were described in the Unit Inventory Modification Section.

REFERENCES

1 Energy Information Administration. Statistics of Privately Owned Electric Utilities 1980. DOE/EIA-0437(80). 1981.

2 Energy Information Administration. Financial Statistics of Selected Electric Utilities 1985. DOE/EIA-0437(85). 1985.

3. Universities Research Group on Energy. Advanced Utility Simulation Model, Documentation of System Design, State-Level Model (Version 1.0). EPA-600/8-88-071c (NTIS PB89-101208), August 1988.

APPENDIX A. STRUCTURAL CHANGES TO AUSM DATA FILES

Data groups accessed by the various modules of the AUSM are contained in external data files. These files contain important driver information -- including both default data and are scenario specific inputs. Changes made to structure of these files since the Universities Research Group on Energy (URGE) delivered the AUSM to the EPA in November of 1984 are outlined below. This document does not identify changes made by SAIC or its subcontractors to specific input parameters within these external data files. Changes of this sort should be transparent to model users.

File	Data Group	
E1	- Exogenous demand inputs	10, 11, 12, 13
E2	- Exogenous planning inputs	20, 21
E3	- Exogenous control technology	30
E4	- Exogenous finance inputs	60, 61, 62, 65
E5	- Unit Inventory	70
E6	- Coal Prices and characteristics	71, 72, 75
E7	- Alternate fuels	73, 74
E8	- Scenario directives	17, 19, 26, 31
E9	- EPOS strategy implementation	26, 35
E10	- Demand model intercept adjustment	18

Table A-1. External AUSM Data Sets

E1 - Exogenous Demand Inputs

Both time dependent and invariant national and state level information are contained within this file. No changes have been made to the structure of this file.

E2 - Exogenous Planning Inputs

This file contains three main sections. Specific power plant information (ie. heat rates, expected lifetimes, total construction costs, etc.) for each of the 23 AUSM technology categories are included in the first section. The second

section contains construction cost spread data for each technology category. The last section is comprised of state specific transmission and distribution costs. Input parameters in this file have been updated, but no changes have been made to the structure of this file.

E3 - Exogenous Control Technology

General pollution control technology information such as emissions factors, retrofit factors, flyash fractions, limb parameters, and other variables are contained in the E3 file. Input parameters in this file have been changed to accommodate new LIMB algorithms, but the structure of the file remains unchanged.

E4 - Exogenous Finance Inputs

Both national and state level financial information are contained in the E4 file. This first part of this file contains national financial data such as depreciation schedules, investment tax credit rates, asset tax lives, and other tax related variables. State level financial information are found in the second part of this file.

Although the structure of the E4 file has not been altered, some of the variables in the finance data groups are now employed differently because of enhancements to the Financial Module. For example, some of the array positions in the depreciation and asset tax life variables read from these data groups are now no longer used. Rather, a new set of depreciation and asset tax life schedules, which comport with the 1986 Tax Reform Act, are now referenced after 1986. In another change, the Federal corporate income tax rate in data group 60 (item identifier 90) is now used only from 1980 to 1986. After that period, the new Federal rates from the Financial Module source code are used.

E5 - Unit Inventory File

The unit inventory file really consists of two databases: an existing unit inventory and an announced unit inventory. Both databases contain information about the operating characteristics of different types of generating units and are ordered by the Federal Information Processing Standard (FIPS) state and county coding scheme. The existing unit inventory contains a description of each steam boiler of 25 MW or greater and each non-steam unit of 50 MW or greater which was on-line as of 1980. Smaller units are represented by "generic" units.

Though no structural modifications have been made to the existing unit inventory file, one of the fields in this file has been redefined. Previously, the third field in the first record of the third section of this file was an unused, left-justified unit identification character field. However, this field now defines two types of units: (a) it identifies a coal unit which is slated to be converted into an oil unit or (b) it identifies a unit containing Canadian hydroelectric power import data. If a "CCNV" flag appears in this field, this unit represents a future coal conversion. However, if a "HIMP" flag appears in this field, this unit contains Canadian hydroelectric power import data. Lastly, if nothing appears in this field it is not used. These flags are important because they affect how the AUSM report writers process certain summary results from a scenario run.

E6 - External Coal File

The E6 file contains information about the least costly coals available to each demand region in selected projection years. No structural changes to this file have been performed.

E7 - Alternate Fuels File

The alternate fuels file describes the physical characteristics and delivered prices of all fuels other than coal to each state. Price projections are given for specified time periods. Default time periods for this file are 1980, 1990, 2000, 2010, 2020, 2030, and 2040. An interpolation routine in the AUSM provides annual prices for the intermediated years. New existing and announced unit inventories are currently being integrated into the AUSM. The existing inventory will contain units which were operational as of 1985. For a more detailed presentation of the structure of this file see the report State-Level Utility Simulation Model: Documentation of the System Design (3).

Because the interpolation or extrapolation routine in the previous version of the AUSM yielded extreme values when the slope changed between two time periods this function was replaced with a new routine based on a spline function. To ensure that this new interpolation procedure was robust, two more years of fuel price data was inserted into the E7 file. Data for the years 1992 and 1995 have now been included. Fuel price data for these years were obtained by interpolating between the two existing intervals -- 1990 and 2000.

E8 - Scenario Directives File

The E8 file contains the user-specified parameters which define and AUSM scenario. This file consists of three sections. Section 1 contains general information used both by AUSM and the report generator (AUSMR). This information includes title and execution dates, as well as the list of states and range of years for which AUSM is to be executed. It also includes a list of all possible reports. Section 2 contains global or national parameters. Lastly, Section 3 contains state-specific scenario parameters.

Section 1

Record	Field	Format	Contents
1	1	blank	
	2-3	I2	Number of 72 column explanatory records (usually zero).
2	1-72	A72	If applicable, text describing MPMS simulation.

Section 2

Record	Field	Format	Contents
1	1	blank	
	2-3	I2	Number of states in region.
2	1-n	m(1x,I2)	State FIPS code; m=record 1, n=3*m.
3	1	blank	
	2-3	I2	Number of simulation time periods (maximum of 16).
4	1	blank	
	2-5	I4	Base year of simulation.
5	1-n	m(1x,I4)	Last year for each time period; m=record 3, n=5*m.
6	1	blank	
	2-3	I2	Number of technology categories (maximum of 10).
7 +	1	blank	
	2-13	2F6.0	Technology code (codelist B) and corresponding fuel code (codelist C) for each National loop technology category.

Section 3

Record	Field	Format	Contents
1	1	blank	
	2-3	I2	State FIPS code
2	1	blank	
	2-49	12F3.0	Fraction of total added capacity by technology type (technologies 1 to 12).
3	1	blank	
	2-49	12F3.0	Fraction of total added capacity by technology type (technologies 13 to 23, position 24 not used).
4	1	blank	
	2-15	F14.3	Interstate transfers (GWh), negative indicates imports.
	16-29	F14.3	SO2 emissions (tons/yr).
	30-43	F14.3	Cost related to emissions (dollars/ton).
	44-57	F14.3	Available capacity per peak demand.
	58-71	F14.3	Ratio of actual annual generation to annual required generation (demand).
5	1	blank	
	2-73	8(1x,F9.1)	Estimated cost of transfers for each year in the time period, years 1 to 8 (Million dollars).
6	1	blank	
	2-73	8F9.1	Estimated cost of transfers for each year in the time period, years 9 to 16 (Million dollars).
7	1	blank	
	2-51	10F5.3	Capacity factor for each plant technology category in time period.
8	1	blank	
	2-6	F5.3	Load factor.
	7-11	F5.3	Base-to-peak ratio.
	12-19	blank	
	20-33	F14.0	Total generation (MWh).
	34-47	F14.0	Total peak capacity (MW).

Table A-2. Structure of the E9 File

Several changes have been made to the E8 file to accommodate enhancements in different AUSM modules. Users may now specify exogenous demand growth rates and exogenous transfer levels for up to 30 years for each state in the E8 file. Users now have the option of establishing different emissions caps for up to ten time periods on a state-by-state basis. If state specific variables 528 to 530 are set to -1 in the E8 file, then the right hand side constraints for SO2, NOx, and TSP emissions are read from external data file. Users may change the parameters in this file. Previously, users could pick just one compliance year in which a new statewide emissions cap could be mandated. After that year, the cap became binding for the balance of the years remaining in the simulation.

E9 - MPMS Data File

The MPMS (multi-period, multi-state) E9 data file is produced by the MPMS planning module in the National loop of AUSM and is an optional input file to the State model. The MPMS planning module develops a preliminary strategy for hardware additions and operating strategies over a multi-state region for multiple time periods. The resulting estimates of interstate energy transfers, state level plant expansions, state emissions caps, and levels of plant operations are directed to the E9 data file.

The E9 data file consists of three sections. Section 1 is a variable length prologue describing the MPMS simulations that created the file. Section 2 contains global information about the simulation region, time periods, and plant technology categories. Section 3 contains both state specific and time specific data. State data are ordered by ascending FIPS code and include information on capacity mix, power transfers and cost, SO2 emissions caps, generation levels, capacity factors, load factors, and base-to-peak ratios. Formats corresponding to these three sections are defined below. Formerly, the E9 data file was known as EPOS (Estimate of Planning and Operating Strategies).

E10 Adjustments to Demand Model Intercepts

The E10 file, data group 18 (DG 18), is read when AUSM users invoke the exogenous demand option with annual recursiveness. This file contains fuel specific weights corresponding to a set of exogenous (total) demand specifications. This option is used when users desire a scenario in which price effects will influence sales. No changes have been made to this file.

Record	Field	Format	Contents
1	1	Integer	Record number identifier.
	2	Integer	FIPS code identifier.
	3	Character	Two letter identifier within apostrophe marks.
	4	Integer	Number of time periods for which sulfur dioxide emissions constraints exist. Note: maximum of 10.
	5	Integer	Number of time periods for which nitrogen oxide emissions constraints exist. Note: maximum of 10.
	6	Integer	Number of time periods for which particulate emissions constraints exist. Note: maximum of 10.
2	1	Integer	Record number identifier.
	2 - 11	Integer	Break year for which a sulfur dioxide emission constraint exist.
3	1	Integer	Record number identifier.
	2 - 11	Real	Maximum level of SO_2 emissions in thousands of tons permitted in a given break year.
4	1	Integer	Record number identifier.
	2 - 11	Integer	Break year for which a nitrogen oxide emission constraint exists.
5	1	Integer	Record number identifier.
	2 - 11	Real	Maximum level of NO_x emissions permitted in a given break year in thousands of tons.
6	1	Integer	Record number identifier.
	2 - 11	Real	Break year for which a particulate emissions constraint exists.
7	1	Integer	Record number identifier.
	2 - 11	Real	Maximum TSP emissions level permitted in a given break year in thousands of tons.

Table A-3. STEMAX Data Set Structure

New Data Groups

In addition to changing the structure of some of the key AUSM external data files, several new data files have been incorporated into the architecture of the model. Brief descriptions of each new file will be presented below. The structure of these files will be highlighted and sample input files will be presented.

Table A-3 shows the structure of the new external emissions cap file discussed above. Emissions constraints may be invoked for any year and for either SO_2,

NOx, or TSP. These selections need not be the same from region-to-region or even from state-to-state. State information is recorded alphabetically. A sample of this is contained in Table A-4.

Two new, state specific data files have been developed as a result of modifications to the dispatch module. First, a file containing state specific capacity factors was created to replace more generic capacity utilization assumptions embedded within the model code. Second, a file consisting of state specific base-to-peak ratios and load characteristics was created because previous load curve information was too uniform across states. An outline of the structure of the capacity factor file and a sample input file are shown in Tables A-5 and A-6. Similar information for the LDC type file is presented in Tables A-7 and A-8.

```
11 01 'AL' 7 7 3 $RECNO FIPS #SO2YRS #NOXYRS #TSPYRS
21 1980    1985    1990    1995    2000    2010    2030 $SO2 YRS
22 -1.   569.5     -1.     -1.     -1.     -1.     -1. $SO2 KTONS
31 1980    1985    1990    1995    2000    2010    2030 $NOX YRS
32 -1.   191.8     -1.     -1.     -1.     -1.     -1. $NOX KTONS
41 1980    1995    2030 $TSP YEARS
42 -1.     -1.     -1. $TSP KTONS
11 04 'AZ' 7 7 3
21 1980    1985    1990    1995    2000    2010    2030 $SO2 YRS
22 -1.     102.    101.     99.     96.     94.     94. $SO2 KTONS
31 1980    1985    1990    1995    2000    2010    2030 $NOX YRS
32 103.    112.    105.    101.     97.     79.     78. $NOX KTONS
41 1980    1995    2030 $TSP YEARS
42 -1.     -1.     -1. $TSP KTONS
11 05 'AR' 7 7 3
21 1980    1985    1990    1995    2000    2010    2030 $SO2 YRS
22 -1.    62.4     -1.     -1.     -1.     -1.     -1. $SO2 KTONS
31 1980    1985    1990    1995    2000    2010    2030 $NOX YRS
32 -1.    77.2     -1.     -1.     -1.     -1.     -1. $NOX KTONS
41 1980    1995    2030 $TSP YEARS
42 -1.     -1.     -1. $TSP KTONS
```

Table A-4. External Emissions Dataset (Partial Listing)

Record	Field	Format	Contents
1	1	Character	Two letter state abbreviation code.
	2	Integer	State FIPS code. Reported in ascending order.
	3	Fraction	Minimum capacity factor: coal units.
	4	Fraction	Maximum capacity factor: coal units.
	5	Fraction	Minimum capacity factor: residual oil units.
	6	Fraction	Maximum capacity factor: residual oil units.
	7	Fraction	Minimum capacity factor: distillate oil units.
	8	Fraction	Maximum capacity factor: distillate oil units.
	9	Fraction	Minimum capacity factor: gas steam units.
	10	Fraction	Maximum capacity factor: gas steam units.
	11	Fraction	Minimum capacity factor: natural gas turbine units.
	12	Fraction	Maximum capacity factor: nuclear units.
	13	Fraction	Maximum capacity factor: hydroelectric units.

Table A-5. Capacity Factor Data Set

```
'AL',01,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.54
'AZ',04,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.78
'AR',05,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.36
'CA',06,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.66
'CO',08,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.29
'CT',09,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.42
'DE',10,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.58
'FL',12,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.89
'GA',13,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.39
'ID',16,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.74
'IL',17,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.49
'IN',18,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.62
'IA',19,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.80
'KS',20,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.47
'KY',21,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.58
'LA',22,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.58
'ME',23,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.64
'MD',24,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.53
'MA',25,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.42
'MI',26,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.52
'MN',27,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.73
'MS',28,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.52
'MO',29,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.21
'MT',30,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.71
'NE',31,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.66
'NV',32,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.78
'NH',33,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.36
'NJ',34,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.14
'NM',35,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.45
'NY',36,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.73
'NC',37,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.44
'ND',38,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.95
'OH',39,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.42
'OK',40,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.39
'OR',41,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.70
'PA',42,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.21
'RI',44,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.19
'SC',45,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.31
'SD',46,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.65
'TN',47,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.61
'TX',48,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.43
'UT',49,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.78
'VT',50,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.55
'VA',51,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.20
'WA',53,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.70
'WV',54,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.53
'WI',55,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.68
'WY',56,.30,1.0,.20,1.0,.010,,.20,1.0,.010,,,.62,,.59
```

Table A-6. State Specific Capacity Factor (CAPFACTS) Dataset

Record	Field	Format	Contents
1	1	Character	Two letter state abbreviation inside of apostrophes.
	2	Integer	State FIPS code.
	3	Integer	State type flag. States with flag set to "1" typically have normal seasonal loading. States with flag set to "2" typically have very high winter/summer peak demand for energy to accommodate increased air conditioning usage.
	4	Fraction	Base-to-peak ratio.

Table A-7. Load Duration Curve File Structure

```
'AL' 01 2 .36
'AZ' 04 2 .38
'AR' 05 2 .38
'CA' 06 2 .40
'CO' 08 2 .49
'CT' 09 1 .34
'DE' 10 1 .34
'FL' 12 2 .36
'GA' 13 2 .47
'ID' 16 1 .41
'IL' 17 1 .36
'IN' 18 1 .40
'IA' 19 1 .34
'KS' 20 2 .36
'KY' 21 2 .33
'LA' 22 2 .50
'ME' 23 1 .49
'MD' 24 1 .34
'MA' 25 1 .35
'MI' 26 1 .46
'MN' 27 1 .41
'MS' 28 2 .30
'MO' 29 2 .30
'MT' 30 1 .42
'NE' 31 1 .30
'NV' 32 2 .30
'NH' 33 1 .34
'NJ' 34 1 .38
'NM' 35 2 .60
'NY' 36 1 .47
'NC' 37 1 .45
'ND' 38 1 .37
'OH' 39 1 .45
'OK' 40 1 .30
'OR' 41 1 .47
'PA' 42 1 .36
'RI' 44 1 .34
'SC' 45 2 .34
'SD' 46 1 .30
'TN' 47 2 .33
'TX' 48 2 .34
'UT' 49 2 .53
'VT' 50 1 .36
'VA' 51 1 .43
'WA' 53 1 .30
'WV' 54 1 .36
'WI' 55 1 .41
'WY' 56 1 .42
```

Table A-8. Load Duration Curve File

APPENDIX B NEW OR CHANGED AUSM VARIABLES

A compilation of new or changed variables contained in the revised Advanced Utility Simulation State Level Model modules is presented below. This list contains only variables which are known to have been affected by coding upgrades.

Financial Module

CHANGED VARIABLES

Variable	Unit	Description
DPRATE	Fraction	Changed array dimension from 15 to 20 elements.
FTXRT	Fraction	Used prior version of the Financial Module to read in the Federal income tax rate. Stored this tax rate for non-taxable states only. Current version of the Financial Module only reads in long-run tax rate.

NEW VARIABLES

Variable	Unit	Description
COCADJ	Real	Array containing adjustments to cost of capital based on COV2.
COV2	Real	COV2 from R602 added to FINAC.
CUTCNT	Integer	Dividend cut counter.
CUTTOL	Fraction	Dividend cut tolerance.
CUTTRG	Integer	Dividend cut trigger.
DP152	Fraction	Tax depreciation rate schedules for 15 year tax lives based on 1986 Tax Reform Act. 20 member array with last five positions equal to zero.
DP201	Fraction	Tax depreciation rate schedules for 20 year tax lives based on 1986 Tax Reform Act.

Financial Module (continued)

Variable	Unit	Description
DPR	Fraction	Current actual dividend payout ratio.
GRTCNT	Integer	Dividend growth counter.
GRTTRG	Integer	Dividend growth trigger.
ICOV2	Integer	Index for cost of capital adjustment.
LTNN	Years	Tax life of an asset under the provisions of the 1986 Tax Reform Act.
NEWDIV	Millions of dollars	Temporary variable for dividend calculation.
OLDNEQ	Millions of dollars	Prior year new common equity.
OLDNET	Millions of dollars	Prior year net income.
SAUFTX	Real	Used to save current Federal tax rate for non-taxable states.
TGTPOR	Fraction	Target dividend payout ratio.

Pollution Control Module

CHANGED VARIABLES

Variable	Description
V	The number of array positions have been increased from 72 to 81 to include unit name.
EMAX	RHS for emissions constraint. If -1, then represents a flag directing the model to use the year-specific RHS from I/O unit 62 (STEMAX entries). Dimensioned (3) representing the three emittants (see JEM).

NEW VARIABLES

Variable	Unit	Description
CASRAT	Fraction	Calcium/sulfur mole ratio.
CAUTZF		Calcium utilization factor.
COLPHR	Pounds/hour	Coal fuel input.
DUCCST	Dollars/kW	Duct humidification system cost.
ECNMOD	Dollars/kW	Economizer modification costs.
EMESC	Kilotons	Escape valve to be used when emission constraint produces an infeasible solution. Dimensioned (3).
FACLIM		Retrofit factor.
FFCADY		F factor, dry basis. Array contains five elements based on coal type. (1) Bit. (2) Sub-Bit (3) Lignite (4) Anthracite (5) Oil.
FLUGAS	lb-mole per Btu MAF (moisture & ash free)	Flue gas level
FURNRM	Fraction	Maximum SO_2 removal allowed in the furnace (without humidification).
HHVFGD	Btu/kWh	Higher heating value for coal. As received.
HUMDRM	Fraction	Additional SO_2 removal due to humidification.
HUMFAC		Humidity factor. Default=0.027.
HVMAF	Btu/kWh	Heating value MAF (moisture & ash free).

Pollution Control Module (continued)

Variable	Unit	Description
INJCST	Real	Capital cost of injection system according to the hydrate lime sorbent flow rate (in lbs./hr).
LIMFAC		Lime factor for hydrated lime.
O2	moles	Oxygen requirement in boiler.
O2CNFL		Oxygen concentration factor.
O2EXS		Excess oxygen level.
PERO2	Percent	Percent oxygen in the furnace.
SBUC	Dollars/kW	Soot blower upgrade cost calculation.
SORB	Pounds/hour	Hydrate lime sorbent rate.
SULHRM	Moles per hour	Coal sulfur input.
TCVFAC		Units conversion constant for SO_2.
TSO2RM	Percent	Furnace SO_2 removal level.
UNSO2C	Parts per million	Uncontrolled SO_2 concentration, wet basis.
UNSO2E	Pounds per MMBtu	Uncontrolled SO_2 emissions.

Dispatching Module

CHANGED VARIABLES

Variable	Unit	Description
UNIT		Number of array positions increased from 72 to 81.
EMAX	1000 tons	RHS for emissions constraint. If -1, then represents a flag directing the model to use the year-specific RHS from Input/Output unit 62 (STEMAX entries). Dimensioned (3) representing the three emittants (see JEM).
EMESC		Escape valve to be used when emission constraint produces an infeasible solution.

NEW VARIABLES

Variable	Unit	Description
JEM		Counter specifying the type of emittant being looped over. 1=SO_2, 2=NO_x, and 3=TSP).
JK		Counter specifying the type of emittant being looped over. 1=SO_2, 2=NO_x, and 3=TSP).
JQ		Counter which loops over the number of emittants. Used to unpack escape valve variables.
JSTX		Breakpoint year index to STEMAX array.
JJX		Counter for breakpoint year in STEMAX data.
JJZ		Positional counter for breakpoint year in STEMAX data.
KKEMX	Integer.	RHS for emissions constraint. If -1, then represents a flag directing the model to use the year-specific RHS from I/O unit 62 (STEMAX entries).
KKYRX		Number of breakpoint years for emission constraint.

Dispatching Module (continued)

NEW VARIABLES

Variable	Unit	Description
KKK		Maps the scenario file identifier with the emittant: 528, 529, and 530 represent SO2, NOx, and TSP, respectively.
NSTYRX		Contains the number of breakpoint years (position 1) and their values (positions 2-11) for each state and each emission type (see JEM). Dimensioned (3,60,11) for (emission type, state, breakpoint year).
STEMAX		Maximum emissions (see JEM) permitted in a given state beginning in a given year. Used to define the RHS of the emissions constraint in the DISPATCH module. Dimensioned (3,60,10).
XEMNM		Stores name of emergency power plant which is used to prevent model interrupt due to LP infeasibility resulting from emissions constraint. Dimensioned (7).
XNAM		Storage array for unit names. Dimensioned (401,7).

CHANGED VARIABLES

Variable	Description
GENRS	Dimension changed from 72 to 81 to include unit names.
IST3	Previously not used. Now defines I/O unit number for STEMAX entries.
UNDFLT	Dimension changed from 72 to 81 to include unit names.
UNITS	Dimension changed from (72,50) to (81,50) to include unit names.

NEW VARIABLES

Variable	Description
AFPS	(Character * 4) Two letter state abbreviation read from I/O unit 62 where the STEMAX values are defined.
IFPS	FIPS code from Codelist I.
JEM	Counter specifying the type of emittant being looped over. Position: (1) SO2 (2) NOx (3) TSP.
NSTYRX	Contains the number of breakpoint years (position 1) and their values (positions 2-11) for each state and each emission type (see JEM). Dimensioned (3,60,11) for (emission type, state, breakpoint year).
NYRX	Number of breakpoint years plus 1.
NYRXX	Number of breakpoint years.
STEMAX	Maximum emissions (see JEM) permitted in a given state beginning in a given year. Used to define the RHS of the emissions constraint in the DISPATCH module. Dimensioned (3,60,10).
XLEQ2	(Real) Temporary storage for annual transfer cost supplied by the AUSM scenario file (E8).

CHANGED VARIABLES

Variable	Description
UNIT	Change array dimension from 72 to 81 to correspond directly with UNITS array in CONTROL module.

CHANGED VARIABLES

Variable	Units	Description
Data Group 70, position 8.		Old Use: Dispatch region. New Use: Stores life of unit as defined in the unit inventory files (E5 and E5A).

NEW VARIABLES

Variable	Units	Description
XLIFE	Real	Life of unit as defined in the unit inventory files (E5 and E5A).
JJUNIT	Integer	Unit sequence number.

NEW VARIABLES

Variable	Units	Description
AEMX	Character	Spaceholder to identify emission type in formatted write. Dimensioned (3).
EMAX	1000 tons	RHS for emissions constraint. If -1, then represents a flag directing the model to use the year-specific RHS from I/O unit 62 (STEMAX entries). Dimensioned (3) representing the three emittants (see JEM).
EMESC		Escape valve to be used when emission constraint produces an infeasible solution.
KJ		Counter.
KK		Counter.
XXX	Kilotons	Quantity of emittant exceeding limit set by RHS in emission constraint. Written as flag to report 505.
ZZZ	Kilotons	Maximum emissions level defined as the RHS of the emission constraint.

APPENDIX C. LIMB ALGORITHM

Based on the most recent test data available, EPA developed the following performance and cost algorithm. It should be noted that the algorithm restricts SO_2 removal in the furnace to 85 percent with humidification and to 80 percent without humidification.

The first step is to determine the calcium to sulfur ratio of sorbent use for the desired emission removal level. This algorithm is shown in Table C-1. The next step is to determine the amount of sorbent flow the lime injection system must be sized to handle and the costs of the system. This second step is shown below:

SORB = MSH * (Ca:S) * 74.08

MSH = (CFI * (SAV/100) / 32.07)

CFI = MW * 1000 * (NHR/HHV)

where:

SORB = Hydrate lime sorbent flow rate (pounds per hour)

MSH = Moles of sulfur per hour

$$Ca/S = (1/B_o) * \ln(1-(R_f/(100*F_c)) \quad \text{for} \quad (R_f/F_c) < 100$$

$$R_f = 100-((100-R_t)/0.75)$$

$$F_c = (C_w^{0.195} * \ln(C_w))/32$$

$$C_w = (E * (1-B_{ws}))/(K * F_d * F_o)$$

$$F_o = 20.9/(20.9-\%O_2)$$

$$E = (64.07/32.07) * 10000 * (S/HHV) * (1-(L/100))$$

B_o	= -0.3893	for hydrated lime
B_o	= -0.4128	for lignosulfonated lime
K	= $1.660 * 10^{-7}$	for SO_2
K	= $1.194 * 10^{-7}$	for NO_x
F_d	= 10,100	for anthracite coal
F_d	= 9,780	for bituminous coal
F_d	= 9,860	for lignite
F_d	= 9,190	for oil, resid., dist.
F_d	= (see below)	for subbituminous coal

where:

$F_d = (3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)) * 10^6 / HHV$

Ca/S = Calcium to Sulfur molar ratio
B_o = Lime factor
R_f = Furnace SO_x removal
F_c = Calcium utilization factor
R_t = Total SO_x removal in furnace (R_f and an additional 25% from humidification)
C_w = Uncontrolled SO_x concentration (ppm, wet basis)
E = Uncontrolled SO_x emissions (lb / MMBtu)
B_{ws} = Humidity factor, default = 0.027
K = Units conversion constant
F_d = F factor, dry basis
F_o = Oxygen concentration factor
$\%O_2$ = Percent oxygen in furnace
L = Boiler sulfur loss (boiler bottoms, flyash, pulverizer)
HHV = Higher heating value
S = Percent sulfur in coal
H = Percent hydrogen in coal
N = Percent nitrogen in coal
O = Percent oxygen in coal
C = Percent carbon in coal

Table C-1. Calcium to Sulfur Ratio Calculation

CFI = Coal fuel input (pounds per hour at 100 percent load)

MW = Capacity of the unit (megawatt)

NHR = Net heat rate of the unit (Btu per kilowatt hour)

HHV = Higher heating value of coal (Btu per pound coal)

SAV = Average coal sulfur content (percent)

Ca/S = Calcium to sulfur ratio (mole ratio)

After the sorbent flow rate was calculated using the Ca/S ratio, the coal/SO2 throughput, and the SO2 removal requirements, the sorbent flow is then used to determine component capital costs and variable operating costs. The various system components whose capital costs were influenced by the sorbent flow rate include:

o Injection system (ISCC)

SORB (lbs/hour)	Equation (dollars)
≤ 26,100	((62.85 * SORB) + 871063 + 1366699) * 0.5
26,100 to 56,749	((62.85 * SORB) + 871063 + 1640039) * 0.5
56,749 to 170,000	((15.994 * SORB) + 1184098 + 1776709) * 0.5
> 170,000	((27.1 * SORB) - 703968 + 2050049) * 0.5

o Soot blower upgrade (SBUC)

SORB (lbs/hour)	EQUATION (dollars per kilowatt)
< 90,000	1.09
≥ 90,000	1.09 + (SORB - 90000) * (1.2142/10000)

- Economizer modification (EMC)

New units: $0.0 per kilowatt

Retrofit units:

SORB (lbs/hour)	Equation (dollars per kilowatt)
< 170,000	4.14
≥ 170,000	4.14 + (SORB - 170000) * (2.6696/10000)

Additional system components where costs were upgraded include:

- Electrostatic precipitator (ESP) upgrade (ESPUC)

New units: No new costs ($0.0/kW) are needed for RNSPS ESPs

Retrofit units: Added costs for "tuning up" the unit ($2.50/kW) and for ESP expansion of ESP capacity to a minimum of 200 ft^2/acfm of specific collection area are included.

SCA (ft^2/acfm)	Equation (dollars per kilowatt)
≤ 200	2.50 + 20.56 * ((200/SCA) - 1)
> 200	2.50

- Duct humidification system (DHC)

All units: $10.00 per kilowatt

- Low NO_x burner (LNBC)

Unit type	Equation (dollars)
New unit, wall fired:	$(500/MW)^{0.6} * 3.70 * MW * 1000$
New unit, tangential:	$(500/MW)^{0.6} * 1.09 * MW * 1000$
Retrofit unit, wall fired:	$(500/MW)^{0.6} * 5.65 * MW * 1000$
Retrofit unit, tangential:	$(500/MW)^{0.6} * 1.37 * MW * 1000$

where MW = capacity of the unit (MW).

The total direct capital cost equations for the LIMB system are:

New units: ISCC + ((SBUC + DHC) * (MW*1000) RFF) + LNBC

Retrofit units: ISCC + ((ESPUC + SBUC + DHC + EMC) * (MW*1000) RFF) + LNBC

where RFF = retofit factor.

APPENDIX D. UNIT SIZES BY TECHNOLOGY AND STATE

The unit sizes are stored in the exogenous planning inputs dataset (file E2) at the region level. Each of the 48 contiguous states model unit size assuming a maximum unit size for each technology category at the region level. This implementation of the file E2 allows the user greater flexibility in selecting maximum unit sizes for a given scenario. The user can modify the file E2 to allow different maximum unit sizes for each region. Until maximum unit sizes can be re-estimated at the region level for each technology category plans are to leave the assumptions unchanged. If unit sizes are estimated for each state unit sizes by technology category for each region will then be stored in the file E2. AUSM plant technology codes are listed in Table D-1. Unit sizes are listed by state and technology category in megawatts on the following pages.

Code	Plant type
0	No data or not used
Combustion Turbines	
1	Natural gas (peaking)
2	Distillate oil (peaking)
3	Residual oil (peaking)
4	Hydro - pumped storage
Conventional Steam	
5	Natural gas
6	Distillate oil
7	Residual oil
8	Solvent refined coal
Combined Cycle	
9	Natural gas
10	Distillate oil
11	Residual oil
12	Pressurized fluidized bed
13	Gasification
14	Gasifier-gas fired boiler
Conventional Steam	
15	Coal
16	Light water reactor (nuclear)
Atmospheric Fluidized Bed	
17	Bituminous
18	Sub-bituminous
Renewables and Other	
19	Hydroelectric dam
20	Magnetohydrodynamic
21	Geothermal
22	Dispersed fuel cells
23	Solar central receiver

Table D-1. Plant Technology Codelist

Technology Category

	Turbine				Steam				Combined Cycle			
	Natural Gas	Dist. Oil	Resid. Oil	Pumped Hydro	Natural Gas	Dist. Oil	Resid. Oil	Solvent Coal	Natural Gas	Dist. Oil	Resid. Oil	Fluid. Bed
State	1	2	3	4	5	6	7	8	9	10	11	12
Alabama	150	150	150	667	500	500	500	500	220	220	220	500
Arizona	150	150	150	667	500	500	500	500	220	220	220	500
Arkansas	150	150	150	667	500	500	500	500	220	220	220	500
California	150	150	150	667	500	500	500	500	220	220	220	500
Colorado	150	150	150	667	500	500	500	500	220	220	220	500
Connecticut	150	150	150	667	500	500	500	500	220	220	220	500
Delaware	150	150	150	667	500	500	500	500	220	220	220	500
Florida	150	150	150	667	500	500	500	500	220	220	220	500
Georgia	150	150	150	667	500	500	500	500	220	220	220	500
Idaho	150	150	150	667	500	500	500	500	220	220	220	500
Illinois	150	150	150	667	500	500	500	500	220	220	220	500
Indiana	150	150	150	667	500	500	500	500	220	220	220	500
Iowa	150	150	150	667	500	500	500	500	220	220	220	500
Kansas	150	150	150	667	500	500	500	500	220	220	220	500
Kentucky	150	150	150	667	500	500	500	500	220	220	220	500
Louisiana	150	150	150	667	500	500	500	500	220	220	220	500
Maine	150	150	150	667	500	500	500	500	220	220	220	500
Maryland	150	150	150	667	500	500	500	500	220	220	220	500
Mass.	150	150	150	667	500	500	500	500	220	220	220	500
Michigan	150	150	150	667	500	500	500	500	220	220	220	500
Minnesota	150	150	150	667	500	500	500	500	220	220	220	500
Miss.	150	150	150	667	500	500	500	500	220	220	220	500
Missouri	150	150	150	667	500	500	500	500	220	220	220	500
Montana	150	150	150	667	500	500	500	500	220	220	220	500

Technology Category

State	- Combined Cycle - Gasifi-cation 13	Gasifier-Gas 14	-- Steam -- Coal 15	Nuclear 16	-- Atmospheric -- Bitum. Bed 17	Sub-bitum. Bed 18	Other Hydro 19	Magneto Hydro 20	Geothermal 21	Fuel Cell 22	Solar 23
Alabama	500	1000	1000	1100	500	500	200	1000	50	10	100
Arizona	500	1000	1000	1100	500	500	200	1000	50	10	100
Arkansas	500	1000	1000	1100	500	500	200	1000	50	10	100
California	500	1000	1000	1100	500	500	200	1000	50	10	100
Colorado	500	1000	1000	1100	500	500	200	1000	50	10	100
Connecticut	500	1000	1000	1100	500	500	200	1000	50	10	100
Delaware	500	1000	1000	1100	500	500	200	1000	50	10	100
Florida	500	1000	1000	1100	500	500	200	1000	50	10	100
Georgia	500	1000	1000	1100	500	500	200	1000	50	10	100
Idaho	500	1000	1000	1100	500	500	200	1000	50	10	100
Illinois	500	1000	1000	1100	500	500	200	1000	50	10	100
Indiana	500	1000	1000	1100	500	500	200	1000	50	10	100
Iowa	500	1000	1000	1100	500	500	200	1000	50	10	100
Kansas	500	1000	1000	1100	500	500	200	1000	50	10	100
Kentucky	500	1000	1000	1100	500	500	200	1000	50	10	100
Louisiana	500	1000	1000	1100	500	500	200	1000	50	10	100
Maine	500	1000	1000	1100	500	500	200	1000	50	10	100
Maryland	500	1000	1000	1100	500	500	200	1000	50	10	100
Mass.	500	1000	1000	1100	500	500	200	1000	50	10	100
Michigan	500	1000	1000	1100	500	500	200	1000	50	10	100
Minnesota	500	1000	1000	1100	500	500	200	1000	50	10	100
Miss.	500	1000	1000	1100	500	500	200	1000	50	10	100
Missouri	500	1000	1000	1100	500	500	200	1000	50	10	100
Montana	500	1000	1000	1100	500	500	200	1000	50	10	100

Technology Category

State	Turbine				Steam				Combined Cycle			
	Natural Gas	Dist. Oil	Resid. Oil	Pumped Hydro	Natural Gas	Dist. Oil	Resid. Oil	Solvent Coal	Natural Gas	Dist. Oil	Resid. Oil	Fluid. Bed
	1	2	3	4	5	6	7	8	9	10	11	12
Nebraska	150	150	150	667	500	500	500	500	220	220	220	500
Nevada	150	150	150	667	500	500	500	500	220	220	220	500
New Hampshire	150	150	150	667	500	500	500	500	220	220	220	500
New Jersey	150	150	150	667	500	500	500	500	220	220	220	500
New Mexico	150	150	150	667	500	500	500	500	220	220	220	500
New York	150	150	150	667	500	500	500	500	220	220	220	500
N. Carolina	150	150	150	667	500	500	500	500	220	220	220	500
N. Dakota	150	150	150	667	500	500	500	500	220	220	220	500
Ohio	150	150	150	667	500	500	500	500	220	220	220	500
Oklahoma	150	150	150	667	500	500	500	500	220	220	220	500
Oregon	150	150	150	667	500	500	500	500	220	220	220	500
Pennsylvania	150	150	150	667	500	500	500	500	220	220	220	500
Rhode Island	150	150	150	667	500	500	500	500	220	220	220	500
S. Carolina	150	150	150	667	500	500	500	500	220	220	220	500
S. Dakota	150	150	150	667	500	500	500	500	220	220	220	500
Tennessee	150	150	150	667	500	500	500	500	220	220	220	500
Texas	150	150	150	667	500	500	500	500	220	220	220	500
Utah	150	150	150	667	500	500	500	500	220	220	220	500
Vermont	150	150	150	667	500	500	500	500	220	220	220	500
Virginia	150	150	150	667	500	500	500	500	220	220	220	500
Washington	150	150	150	667	500	500	500	500	220	220	220	500
W. Virginia	150	150	150	667	500	500	500	500	220	220	220	500
Wisconsin	150	150	150	667	500	500	500	500	220	220	220	500
Wyoming	150	150	150	667	500	500	500	500	220	220	220	500

Technology Category

State	- Combined Cycle - Gasifi-cation 13	Gasifier-Gas 14	-- Steam -- Coal 15	Nuclear 16	-- Atmospheric -- Bitum. Bed 17	Sub-bitum. Bed 18	Other Hydro 19	Magneto Hydro 20	Geothermal 21	Fuel Cell 22	Solar 23
Nebraska	500	1000	1000	1100	500	500	200	1000	50	10	100
Nevada	500	1000	1000	1100	500	500	200	1000	50	10	100
New Hampshire	500	1000	1000	1100	500	500	200	1000	50	10	100
New Jersey	500	1000	1000	1100	500	500	200	1000	50	10	100
New Mexico	500	1000	1000	1100	500	500	200	1000	50	10	100
New York	500	1000	1000	1100	500	500	200	1000	50	10	100
N. Carolina	500	1000	1000	1100	500	500	200	1000	50	10	100
N. Dakota	500	1000	1000	1100	500	500	200	1000	50	10	100
Ohio	500	1000	1000	1100	500	500	200	1000	50	10	100
Oklahoma	500	1000	1000	1100	500	500	200	1000	50	10	100
Oregon	500	1000	1000	1100	500	500	200	1000	50	10	100
Pennsylvania	500	1000	1000	1100	500	500	200	1000	50	10	100
Rhode Island	500	1000	1000	1100	500	500	200	1000	50	10	100
S. Carolina	500	1000	1000	1100	500	500	200	1000	50	10	100
S. Dakota	500	1000	1000	1100	500	500	200	1000	50	10	100
Tennessee	500	1000	1000	1100	500	500	200	1000	50	10	100
Texas	500	1000	1000	1100	500	500	200	1000	50	10	100
Utah	500	1000	1000	1100	500	500	200	1000	50	10	100
Vermont	500	1000	1000	1100	500	500	200	1000	50	10	100
Virginia	500	1000	1000	1100	500	500	200	1000	50	10	100
Washington	500	1000	1000	1100	500	500	200	1000	50	10	100
W. Virginia	500	1000	1000	1100	500	500	200	1000	50	10	100
Wisconsin	500	1000	1000	1100	500	500	200	1000	50	10	100
Wyoming	500	1000	1000	1100	500	500	200	1000	50	10	100

APPENDIX E. UNIT CAPACITY FACTOR LIMITS

The AUSM default unit capacity factor minimums and maximums are presented in this Appendix. These capacity factors are stored in the CAPFACTS file.

	Coal		Residual Oil		Distillate Oil	Gas Steam		Gas Turb.	Nuclear	Hydro
State	Min	Max	Min	Max	Min	Min	Max	Min	Max	Max
Alabama	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.54
Arizona	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.78
Arkansas	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.36
California	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.66
Colorado	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.29
Connect.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.42
Delaware	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.58
Florida	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.89
Georgia	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.39
Idaho	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.74
Illinois	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.49
Indiana	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.62
Iowa	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.80
Kansas	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.47
Kentucky	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.58
Louisiana	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.58
Maine	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.64
Maryland	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.53
Massa.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.42
Michigan	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.52
Minnesota	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.73
Missi.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.52

Note: For distillate and gas turbine units no maximum capacity factor is assumed. For nuclear and hydro electric units no minimum capacity factor is assumed.

State	Coal		Residual Oil		Distillate Oil	Gas Steam		Gas Turb.	Nuclear	Hydro
	Min	Max	Min	Max	Min	Min	Max	Min	Max	Max
Missouri	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.21
Montana	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.71
Nebraska	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.66
Nevada	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.78
New Hamp.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.36
New Jersey	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.14
New Mexico	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.45
New York	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.73
N. Carol.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.44
N. Dakota	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.95
Ohio	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.42
Oklahoma	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.39
Oregon	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.70
Pennsyl.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.21
Rhode Isl.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.19
S. Carol.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.31
S. Dakota	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.65
Tennesse	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.61
Texas	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.43
Utah	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.78
Vermont	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.55
Virginia	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.20
Washington	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.70
W. Virg.	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.53
Wisconsin	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.68
Wyoming	.30	1.0	.20	1.0	.01	.20	1.0	.01	.62	.59

Note: For distillate and gas turbine units no maximum capacity factor is assumed. For nuclear and hydro electric units no minimum capacity factor is assumed.